Original

COMMONWEALTH OF KENTUCKY
KENTUCKY PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER FOR APPROVAL, TO THE EXTENT NECESSARY, TO TRANSFER FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES LOCATED IN KENTUCKY TO PJM INTERCONNECTION, L.L.C. PURSUANT TO KRS 278.218

CASE NO. 2002-00475

TRANSCRIPT OF EVIDENCE

DATE OF HEARING: MARCH 25, 2003

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CHAIRMAN HUELSMANN:

Good morning. The record should reflect it's March 25, a little after nine, and we're here on the case of AEP transfer of control to PJM, Case No. 2002-00475. I would like to enter appearances for the record.

MR. OVERSTREET:

Thank you, Your Honor. I'm Mark R. Overstreet with the firm of Stites & Harbison, P. O. Box 634, Frankfort, Kentucky 40602-0634. I'm here on behalf of the applicant, Kentucky Power Company d/b/a American Electric Power and appearing here with me today is Kevin Duffy, who is with American Electric Power Service Corporation.

CHAIRMAN HUELSMANN:

Welcome, Mr. Duffy. The Attorney General's Office?

MS. BLACKFORD:

Elizabeth Blackford for the Office of the Attorney General, 1024 Capital Center Drive, Frankfort 40601.

CHAIRMAN HUELSMANN:

KIUC?

MR. KURTZ:

Mike Kurtz, Boehm, Kurtz & Lowry, for Kentucky Industrial Utility Customers.

CHAIRMAN HUELSMANN:

And PJM Interconnection?

MR. CALDWELL:
Brent Caldwell with McBrayer, McGinnis, Leslie & Kirkland, 201 East Main Street, Suite 1000, Lexington, Kentucky 40507, and with me today is Bryan Little, Senior Counsel for PJM.

CHAIRMAN HUELSMANN:
Welcome, Mr. Little. Before we start the hearing - or for the Commission?

MR. RAFF:
For the Commission and the Staff, Richard Raff.

CHAIRMAN HUELSMANN:
Before we start the hearing, is there any matters that we need to take up at this stage of the proceeding?

MR. CALDWELL:
There is a motion pending to allow Mr. Little to practice pro hac vice, in the file, or it may not be in the file.

MR. RAFF:
Your Honor, I don't believe the Commission has the authority to grant anyone the right to practice law. I think the rule is that, if you're accompanied by a licensed attorney in Kentucky, that that is authorized.

CHAIRMAN HUELSMANN:
We're going to allow Mr. Little to participate . . .

MR. CALDWELL:

Thank you, Your Honor.

CHAIRMAN HUELSMANN:

. . . and the rule, as I remember the rule with respect to the Hustler case when it was at the United States Supreme Court is the Court has the power to grant pro ad hoc vice and revoke it based upon their determination. I assume an agency has that same basis, and therefore we're going to allow Mr. Little to participate, if he desires to, in the matter limited to this particular case from that standpoint.

MR. LITTLE:

Thank you, Your Honor.

MR. OVERSTREET:

Your Honor, . . .

CHAIRMAN HUELSMANN:

Mr. Overstreet?

MR. OVERSTREET:

. . . we expect to receive a little later this morning the Affidavit of Publication of the notice of this hearing, and I would ask just to request the leave to file it when it arrives.

CHAIRMAN HUELSMANN:

That will be granted. When you get that, at an appropriate time, tell us and we'll put that in as AEP

No. 1, when it gets here. Anything else? I guess I should ask if there's any public comment. I see people out in the audience. Anybody from the public want to comment? Hearing none, the record should reflect that no one has raised their hand or tried to come forward. Mr. Overstreet, do you want to call your first witness?

MR. OVERSTREET:

Thank you, Your Honor. We would call J. Craig Baker.

WITNESS SWORN

The witness, J. CRAIG BAKER, after having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. OVERSTREET:

Q. Mr. Baker, would you please state your name and business address for the record, sir?

A. J. Craig Baker. I work at 1 Riverside Plaza, Columbus, Ohio, and I work for American Electric Power Service Corporation.

Q. And, Mr. Baker, did you cause to have filed on December 19, 2002, in this proceeding, testimony?

A. Yes, I did.

Q. And were certain parts of that testimony updated in connection with Responses to Data Requests filed in this proceeding?

A. Yes, there have been a number of actions that have taken place since then, and they are reflected in the Data Requests.

Q. Mr. Baker, if you were asked the questions set forth in your prefiled testimony, would your answers be the same as amended by the Responses to the Data Requests?

A. Yes, they would.

MR. OVERSTREET:

The witness is ready for cross examination.

CHAIRMAN HUELSMANN:

Ms. Blackford?

MS. BLACKFORD:

I believe that we have discussed an order of procedure in which Staff will go first, if that is agreeable to the Commission.

CHAIRMAN HUELSMANN:

Okay. Staff and then who next or is that just on this witness? Okay. On this witness, Staff will go first.

MS. BLACKFORD:

Yes.

CHAIRMAN HUELSMANN:

Mr. Raff?

MR. RAFF:

Thank you, Your Honor.

CROSS EXAMINATION

BY MR. RAFF:

Q. Good morning, Mr. Baker.

A. Good morning.

Q. Could you turn, please, to your Responses to the 1st Information Request, Item No. 1, in which you indicate that no cost-benefit analysis was done regarding membership in PJM, and the reason was that, it says, here, "AEP is required to participate in an RTO as a condition of FERC's approval of its merger with the former Central and South West Corporation"; is that correct?

A. That is correct.

Q. Okay. Let me show you a copy of the FERC merger approval Order and, in particular, if you will refer to Page 9 of that Order, please.

CHAIRMAN HUELSMANN:

We need one for the Court Reporter, and we'll mark that for identification purposes only as PSC No. 1.

PSC EXHIBIT 1

(MARKED FOR IDENTIFICATION)

Q. Under "Effects on Competition," if you would read through the text on that page and, in particular, starting with the third paragraph from the bottom and then specifically the second paragraph from the bottom, where it says, "AEP has committed to join a Regional Transmission Organization that will be responsible to transmission access and/or the OASIS site, obviating even an appearance of preference by AEP"; is that accurate?

A. As part of the merger negotiations at the Federal Energy Regulatory Commission, as well as in certain state hearings associated with it, AEP was requested to commit to join an RTO as part of that process, and we did, as part of that process, commit to joining an RTO or to joining an RTO by a certain date.

Q. Well, I take it, then, you can't point to any Order in which FERC said, in order to proceed with the merger, you have to join an RTO?

A. I'm not exactly sure where this entry would be, but my recollection is that there was, as part of the merger, a condition placed on AEP that AEP would be in a fully functioning RTO by 12-31-2001.

Q. But did that condition grow out of your commitment voluntarily to join an RTO?

A. The commitment was to file an application to join an RTO with the FERC by a certain date, and the condition was what FERC required and stated we needed to do as part of the merger.

MR. OVERSTREET:

Mr. Chairman, may we go off the record for a moment?

CHAIRMAN HUELSMANN:

But let's stand in recess for a second.

OFF THE RECORD

CHAIRMAN HUELSMANN:

We're back on the record.

MR. OVERSTREET:

Thank you.

Q. Your counsel pointed out that what I've handed you is the ALJ's Initial Decision; not the FERC's decision that followed this Initial Decision. Do you see that?

A. I do see that this is marked the "Initial Decision"; yes.

Q. Okay. And that still reflects that AEP committed to join a Regional Transmission Organization and that was prior to the FERC entering any Order; is that correct?

A. That was part of the settlement that we entered into with various parties including the staff of the Federal Energy Regulatory Commission.

Q. Thank you. In the Response to Data Requests, the 1st Set, Item No. 7, we asked about the rate that would be paid or allocated or assessed to Kentucky Power as part of its membership in PJM and your Response in Paragraph

b. indicates that Kentucky Power would be paying a net charge of approximately $3 million a year for membership in PJM; is that correct?

A. That's correct.

Q. And I believe that we've also asked a number of questions in an effort to determine whether AEP has been able to quantify the benefits in terms of dollars and cents, and, at least from what I have seen, there has been no quantification of those benefits. Is that a fair statement?

A. That is a fair statement. We performed no formal cost-benefit analysis. As we discussed earlier, AEP believes that, as a condition of its merger, it is required to join an RTO. We have looked and directionally we think there are some benefits associated with joining an RTO that will go somewhat to offset those but have not formally calculated what those are.

Q. All right. Thank you. Let me show you copies of statutes that were recently enacted in the year 2002 in Kentucky.

MR. RAFF:

If we could have the one that's 278.212 identified as Staff Exhibit No. 2 and then the statute that's numbered 278.214 identified as Staff Exhibit 3, please.

PSC EXHIBITS 2 and 3
(MARKED FOR IDENTIFICATION)

Q. In regards to the Exhibit 2, the 278.212, have you seen this statute before, Mr. Baker?

A. I don't know whether I have or not.

Q. Okay.

A. I may have at some point.

Q. All right. I would like to focus in on Paragraph (2) of that statute. Could you read that into the record, please?

A. Paragraph (2) states: "Notwithstanding any other provision of law, any costs or expenses associated with upgrading the existing electricity transmission grid, as a result of the additional load caused by a merchant electric generating facility, shall be borne solely by the person constructing the merchant electric generating facility and shall in no way be borne by the retail electric customers of the Commonwealth."

Q. If Kentucky Power transfers control of its transmission facilities to PJM, will Kentucky Power be able to be in compliance with this statute?

MR. OVERSTREET:

Your Honor, I think he's asking the witness a legal question, and he's not qualified to express an answer, so I'll object.

CHAIRMAN HUELSMANN:

You don't want him to answer that question to the best . . .

MR. OVERSTREET:

I . . .

CHAIRMAN HUELSMANN:

Normally, the way we do it is to the best of his ability. You're correct; it is a legal question, and we could do it as a Data Request, and have someone from AEP answer that as a Data Request, or do you want him to try to answer the best he can based upon his knowledge, training, and experience?

MR. OVERSTREET:

I think that, since he's not qualified to give a legal response, I would ask that he not answer the question.

CHAIRMAN HUELSMANN:

Okay. Would you like AEP to answer that question with someone who . . .

MR. RAFF:

Well, let me rephrase it.

Q. Mr. Baker, are you familiar with the tariffs that PJM has on file with the FERC regarding funding for

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transmission expansions?

A. Yes, I am.

Q. Does that tariff mandate that any upgrades to the existing transmission grid that would result from additional load caused by merchant electric generating facilities the costs are then borne by the merchant facility?

A. I know, in some cases, new facilities are charged directly to customers, and then, in some cases, new facilities are rolled into the average rate. I'm not sure what the specifics are of how that delineation is made, but it can be done both ways.

Q. Okay. It comes down to, then, an analysis of the specific facts of the generator and what facilities need to be constructed and what uses will be put of those facilities?

A. I believe that's the case.

Q. Thank you. With regards to what we've identified as Exhibit No. 3, the Statute 278.214, curtailment of service, have you seen that tariff before?

A. Yes, I have seen this one.

Q. And do you know whether PJM currently has in force certain rules and regulations regarding the interruption of transmission service when there are emergencies on the system that's under its control?

A. Yes, I would believe they do have such rules in place.
Q. All right. Do you believe that their rules state that, within a particular jurisdiction, that the highest priority goes to serving the native load?
A. I believe that the priority goes to serve all firm users of the transmission system and that would include native load.
Q. And it would include other than the native load of the utility that owns the transmission facilities; would it not?
A. It could include others as well; yes.
Q. All right. Thank you. Have you seen the testimony filed by PJM witness Mr. Ott?
A. I have done a review of that. I have read it.
Q. He files a cost analysis as an attachment to his testimony; is that correct?
A. There is an analysis, yes, attached.
Q. Did you or anyone from AEP participate in the preparation of that analysis?
A. No, we did not.
Q. All right. Had you seen it prior to its being filed here as an attachment to Mr. Ott's testimony?
A. Yes. The PJM representatives had shared that study with us. I would say it was probably a few months ago, a couple of months ago or a few months ago. I don't

remember the exact date, but, yes, prior to them filing it here, we had seen it.

Q. Has it changed any since you originally saw it a few months ago?

A. The format has changed a little, but it is not - the numbers, as I understand it, are consistent with what we were shown when it was initially done.

Q. All right. Would it be appropriate to ask you questions about that study, or would it be more appropriate to ask Mr. Ott about the study?

A. I believe it would be more appropriate to ask Mr. Ott. As I said, we didn't have anything to do in performing the study itself.

Q. All right. So PJM didn't call you to get inputs for the study?

A. I don't know of any. We certainly didn't have an active role. Whether or not someone made a call and asked for a specific piece of data, that I can't confirm, one way or the other, but we certainly were not an active participant in it.

MR. RAFF:

All right. I think that's all the questions we have for Mr. Baker, Your Honor.

CHAIRMAN HUELSMANN:

From the intervenors, who's going to be next?

MS. BLACKFORD:

I am.

CHAIRMAN HUELSMANN:

Ms. Blackford.

CROSS EXAMINATION

BY MS. BLACKFORD:

Q. Mr. Baker, of the potential $3 million added cost, what, if anything, will be flowed through to Kentucky Power Company customers and how?

A. The $3 million cost, assuming that's the number, you know, that ultimately we experience, would be, I believe, treated as an expense in a rate case on a going-forward basis, and it would be shared between Kentucky customers, whether they be retail or wholesale.

Q. And only as a portion of base rates is what you're saying?

A. As far as I know, those charges would be base rate. I don't know of any that would flow through the fuel clause at this point.

Q. Will, as I understand it, PJM functions in some regards as a seller of off-system power on behalf of AEP as a member through its systemwide economic dispatch?

A. I don't think - I'm not sure I agree with the exact way you represented that, but let me try to clarify. AEP, once it is in PJM, will be able to bid its generating resources into the PJM model, and, if they are dispatched by the PJM system, we will receive payment associated with the dispatch of those generating units and the production of electricity. So they will actually be compensating us for generating power.

Q. Perhaps what I had failed to previously understand, and I want to be sure that I am following it . . .

A. Uh-huh.

Q. . . . correctly now, is whether the company must offer its generation into the day-ahead market in order to be a part of the economic dispatch Order or whether simply by virtue of being a part of PJM, a member of PJM, it begins to be a part of an overall economic dispatch utilizing all generation within the region?

A. The company has as an option to either participate and bid in its generating resources or, as it's termed, "self schedule" its generating resources to meet its load. That load would include, naturally, its native load as well as bilateral transactions that the company had entered into on behalf of itself and indirectly for its customers or you could, if you so choose, bid in your entire generating portfolio into the day-ahead market and purchase back out that which you need to serve your load commitment, but it's an option.

Q. Among the advantages presented were that it is more profitable to be a part of the PJM market inasmuch as it serves the Northeast or more of an eastern portion than does MISO, and I guess what I'm curious about is where the profitability factor is expected to arise. Is it through the absence of through and out rates? Is it through being a part of the economic dispatch Order? Where is the expanded profitability expected to arise?

A. We believe that the generation production costs are higher although not inordinately higher but somewhat higher in PJM than in MISO, and it would be through sales either through the economic dispatch or bilateral transactions between AEP and other parties in the PJM area.

Q. Would the AEP generating systems stand at the bottom of the stack, so to speak, in terms of generation costs for the most part?

A. I don't believe we would - let me phrase this differently. AEP has, in its system, various production costs at its generating plants, just as most utilities do. So we will probably have some generating units at the lower end of the cost profile for all of PJM. We will have some that will be kind of midrange, but what AEP does not have is a lot of very expensive generating units. So we will be kind of at the low, middle, and perhaps upper middle, but we will not be at the high end of the dispatch curve.

Q. Looking at this from a more specific point of view of Kentucky Power Company, am I correct in saying that Big Sandy would be one of the low-cost generators?

A. I would believe it would be toward the low end. There are nuclear facilities in PJM which have a very low cost, but, on, you know, a coal, gas, or oil, I would believe that the Big Sandy Plant would be at the lower end of those type of units.

Q. What, then, are the advantages that run to Kentucky Power versus AEP as a whole from being a part of PJM?

A. The benefits that we had outlined, but specifically in regards to the area you're discussing there is an expectation that AEP will be able to make incremental sales on behalf of the entire system, and the benefits of additional sales flow through to Kentucky as well, even if they're not produced at Big Sandy, as a result of the AEP Pool Agreement which shares profits on off-system sales via MLR. There also may be times where, during off-peak periods, there would be a situation where there would be power that would be more economic than even Big Sandy, and, at that point, if Big Sandy were not chosen to dispatch, we could bid it in and, if some other cheaper source was available, the cheaper source would be bought and produce lower production costs for the AEP System, again, some of those benefits coming to Kentucky through the Pool.

Q. So am I correct in understanding that it is the Pool that will be buying and selling in the sense of off-system transactions within PJM?

A. I'm sorry.

Q. I don't know if my question is vague or whether I'm simply not knowledgeable enough to ask correctly. Will all sales come and go through the AEP Pool or will they come and go through the individual subsidiaries?

A. The AEP Service Corporation performs an agent function for the five operating companies in the AEP Pool, and it is the party that dispatches the system and makes sales and purchases on behalf of the five companies.

Q. And will all payments then be made to the service company and distributed essentially through the Pool?

A. Payments associated with purchases and sales are distributed through the pooling arrangement.

Q. Now, what about the administrative costs? Are they also coming through the Pool and are assigned only in connection with member load ratio?

A. There is no direct reference to these kind of costs, but I believe they would generally be allocated via the

MLR.

Q. Well, the company had expressed some concern with the FTRs and the movement to an annual auction versus a monthly auction of FTRs by PJM. What is the basis of the concern there?

A. We're coming up to speed, hopefully, quickly on the use of FTRs as the insurance policy, I'll call it, against congestion costs that are incurred. We believe that having the ability to change your FTRs to make sure that you properly align where you think your generation is going to come from as well as where your load is produces additional protection, and we have been talking to PJM and learning on how best to accomplish that. We also have looked at the ability to treat the whole AEP System as one large zone which may minimize our concerns, but that is something we're still working on with PJM and with the PJM stakeholders to find the best methodology.

Q. Am I correct in understanding that the FTR is a financial settlement and that it does not actually stop constraints; it merely somehow ensures against the price of constraints in LMP?

A. FTRs themselves are purely a financial instrument. The use of LMP, though, is a more sophisticated model for managing congestion in the current TLR process, but the

FTRs themselves are purely a financial instrument.
Q. Do the FTRs speak to firm transmission where locational marginal pricing speaks to real-time or day-ahead markets or are the two synonymous?
A. I'm sorry. Could I have that question read back . . .
Q. Sure.
A. . . . or could you restate it?
Q. As I understand it, the FTRs are allocated based on annual expected need for firm transmission; is that correct?
A. Yes, I believe that's a fair representation.
Q. Are they then somehow tied into or do they overlay or work against the locational marginal pricing or is locational marginal pricing solely a function of the day-ahead and real-time markets?
A. The locational marginal pricing is a function of the day-ahead and real-time markets. The FTRs are a methodology where people are paid for having those rights and that is used to offset the cost that is incurred as a result of locational marginal pricing and charges for transmission service that result from the differences in locational marginal pricing. I will be happy to answer these questions, but you probably have an expert coming up as a later witness who clearly has a higher level of expertise than I do.

MS. BLACKFORD:
All right. Thank you. That's all of my questions.
CHAIRMAN HUELSMANN:
Mr. Kurtz?
MR. KURTZ:
Thank you, Mr. Chairman.
CROSS EXAMINATION
BY MR. KURTZ:
Q. Good morning, Mr. Baker.
A. Good morning.
Q. For AEP to join PJM, AEP needs a number of state commission approvals; is that correct?
A. I think that is a legal question that I am not expert to answer.
Q. Well, let me ask you this; what's the status of the Virginia approval process?
A. The status of the Virginia approval process is that we have filed with the Virginia State Corporation Commission. We've been asked to supply additional information to that commission. No procedural schedule has been set in our request for approval to transfer the control.
Q. Didn't Virginia pass a law prohibiting the transfer for some period of time?

A. The Virginia Legislature passed a Bill which prohibited companies in Virginia from joining an RTO prior to, I believe it is, July 1, 2004 and requiring companies to be in RTOs by January 1, 2005.

Q. Has AEP taken legal action to try to counteract that new Virginia legislation? For example, have you gone to AEP to try to override that state's legislation?

A. I'm sorry. I . . .

MR. OVERSTREET:

Do you mean FERC, Mr. Kurtz?

MR. KURTZ:

What did I say?

MR. RAFF:

You said "AEP."

CHAIRMAN HUELSMANN:

AEP.

MR. KURTZ:

Oh, yeah.

Q. Did AEP go to FERC to try to override that legislation in any way?

A. AEP provided the FERC, and I don't remember the exact term, but I'll kind of explain it, a status update to the FERC not long after that Bill had passed the House, and, in that, we informed the Commission, the Federal Energy Regulatory Commission, not this Commission, that we understood that we had a merger condition. We now had a state law on the books saying we were prohibited from doing it and suggested that it was important for the Federal Energy Regulatory Commission and state commissions to have a dialogue about what our merger requirements are as far as an RTO and to help us see our way through what apparently is becoming a state/ federal conflict.

Q. Has Virginia enacted retail deregulation?

A. Yes, it has.

Q. Okay. When is that supposed to go into effect?

A. It went into effect, I believe it was, 1-1-2002.

Q. So there's a state, I guess, for example, that believes that delaying an RTO transfer of transmission assets is appropriate even though that state has got some form of deregulation on the books?

MR. OVERSTREET:

I'm going to object to the question. I'm not sure Mr. Baker is qualified to testify to why that the Virginia General Assembly enacted the statute.

MR. KURTZ:

I'll withdraw the question.

Q. You're obviously in front of this Commission seeking approval of the transfer of Kentucky Power's transmission; is that correct?

A. We've asked for their approval to transfer; yes.
Q. Do you need this Commission's approval to transfer those assets to PJM?
MR. OVERSTREET:
Are you asking a legal question, Mr. Kurtz?
MR. KURTZ:
I'm asking why we're here.
Q. Do you need the Commission's approval to transfer the control of Kentucky Power's transmission assets to PJM?
A. I'll answer that from a business standpoint; not from a legal standpoint. From a business standpoint, we feel we're in a bit of a bind between what states believe they have as far as approval rights and what the FERC may or may not believe about their right to order us in. We preferred not to get cross with any of the commissions that we deal with, and so we wanted to come before this Commission and ask for approval and hope that we wouldn't have to deal with the legal question of conflicting state and federal Orders.
Q. Assume that this Commission finds that the transfer is not in the public interest, do you know what course of action AEP will take?
A. No, I do not.
Q. Do you know whether or not this Commission can condition its approval? In other words, say, "Yes, you

may transfer provided you meet these conditions"?
MR. OVERSTREET:
I object. He's asking a legal question about the Commission's authority.
CHAIRMAN HUELSMANN:
I think probably Mr. Overstreet is correct. We'll take judicial notice, I think, on certain things.
MR. KURTZ:
Okay.
Q. If this Commission gives approval to transfer control of the transmission assets to PJM, can this Commission ever take it back?
MR. OVERSTREET:
The same objection, Your Honor.
CHAIRMAN HUELSMANN:
I think he can answer that one, if he can.
A. Okay. I'm sorry. Could you rephrase the question or restate the question?
Q. If the Commission gives approval and then decides later on it was a bad idea, can it take back the approval?
A. That, to me, is a legal question, and I don't have the expertise to answer it.
Q. If it was a one-time decision, in other words, the Commission could never take it back, wouldn't that make this a more important decision versus a situation where

the Commission could reconsider at some future time?
A. I guess that depends. One is that one would have to find later that it was a bad idea. It would depend on whether or not RTOs were the same as they are today or different. It's hard for me to say. I would have to look at the conditions at the time that the Commission was thinking of a change and see whether that made it more difficult or not. I just don't know.
Q. I believe, in your Response to Staff Data Request No. 1, you indicated that there was no cost-benefit analysis done regarding this transfer.
A. Yes.
Q. Okay, and, in Response to Staff Data Request 7, you indicated that the costs would be approximately $3 million a year. Do you remember that question?
A. Yes.
Q. Does that include all the costs associated with this? For example, would that include the increased rate of return on equity that FERC has given to RTO transmission assets?
A. That number, I believe, is only the administrative charge that PJM will be charging AEP Kentucky's share of it. It does not include any potential ROE treatments at FERC for wholesale transactions.
Q. What about congestion costs? Does the $3 million

include congestion costs?
A. No, it didn't. AEP does not think its system has a heavy congestion, and it's been generally represented to us, both by PJM as well as other parties, that the FTRs are a very effective means of ensuring against those congestion costs, so we don't think it's going to be of a material nature at this time.
Q. Are there any other costs that the $3 million did not include that you can think of?
A. I think it's better to describe it that those are the administrative costs. I don't know of anything else.
Q. I want to ask you a few questions about transmission versus generation. When I think of PJM, I think of a transmission organization. Is that generally what it is?
A. I think it is a combination of things. It is a transmission organization as well as an organization that runs an energy market and has certain market rules around that energy market.
Q. Now, if this Commission grants transfer of Kentucky Power's transmission to PJM, I want to ask you some questions about what effects that will have on the generation that Kentucky Power owns. Can you generally describe what effects, what type of control, PJM will then have over Kentucky Power's generation resources?

A. The major control that PJM will have over the AEP generating assets is they can require AEP to redispatch generating units to relieve congestion. There is also a coordination function that they perform as far as scheduling of generation outages. I think those are the major areas where PJM can influence the AEP generation.

Q. Now, you understand that, historically, this Commission has had complete jurisdiction over the generation, at least the generation owned by the utilities regulated by this Commission? Is that your general understanding?

A. They have jurisdiction over the generation assets; yes.

Q. Let's talk about dispatch for a moment. PJM can order Kentucky Power to dispatch its units to relieve congestion. That's what you just stated; is that correct?

A. Yes, I believe that they can.

Q. Okay. Now, if PJM were to file at FERC and ask for a change to its dispatch authority, would PJM be able to dispatch for more reasons than relieving congestion? In other words, would a mere filing at FERC give PJM even greater control over generation dispatch?

A. Well, there would be - that's a long process. You would have to go through various stakeholder processes at PJM. You would have to go through a Board. You would have to go through the whole FERC process where parties would be intervening. I'm not sure what they would want more than they already have based on their charter of what they're supposed tp perform. I guess they could file something at the FERC asking for, you know, additional control, but I'm not sure why they would.

Q. Well, I guess I'm asking this because there was no answer to my question of whether the Commission could undo its approval and then, once this approval, assume it's given, what may occur in the future, and I take it that, even though the process is cumbersome, somebody could go to FERC and say, "We want even greater control over the dispatch of the generation of PJM," and, presumably, FERC could grant that; isn't that right?

MR. OVERSTREET:

Your Honor, I think he's asking the witness to speculate. He has not really laid a hypothetical with enough facts for Mr. Baker to intelligently respond.

CHAIRMAN HUELSMANN:

I think he can answer that question. It may be hypothetical, but I think he can answer the question. He's been around a long time.

A. Sure. Thank you, Your Honor.

CHAIRMAN HUELSMANN:

Not that long. I think . . .

A. I guess there is always the possibility that a Regional Transmission Organization could make a filing at the FERC asking for more control over the generation assets that are tied to the grid that they have some responsibility for. If that happens, it will go through a federal process, and it may go to Court, but ultimately there will be a decision on it, and I guess it could impact what a company could do with its generating assets. It's possible.

Q. So, hypothetically, FERC could enact some measure in an attempt to equalize generation costs throughout a region; isn't that right?

A. I honestly don't know whether that would pass a legal standard or not.

Q. One question I meant to ask and I forgot, can AEP unilaterally pull out of PJM, assuming you join? In other words, if you got all the approvals and you join day one and you decide that a month later it's not a good idea, could AEP pull out?

A. There is withdrawal provisions which are not overly restrictive from a timing standpoint being able to withdraw from PJM.

Q. Could this Commission - assume that all the approvals were given and that AEP and Kentucky Power join PJM, could this Commission order Kentucky Power to pull out?
MR. OVERSTREET:
Your Honor, I'm going to object again. He's asking for a legal conclusion.
CHAIRMAN HUELSMANN:
I think, if he can answer that, let him answer it.
A. You know, I tend not to answer or speculate on what state commissions, you know, can or will do. It has not served me well over the long period of time I've been around.
Q. But you don't know if this Commission could order Kentucky Power to pull out?
A. I don't know.
Q. Okay. Doesn't PJM have some generation reserve margin requirements known as ICAP, I-C-A-P, or otherwise?
A. Yes, they have reserve requirements just as we have reserve requirements in a somewhat similar fashion under our Reliability Council, ECAR.
Q. Could you describe what PJM's reserve margin authority is?
A. As part of the process of being a participant in the market, one must either have a certain amount of ACAP or ICAP, and the region, for example, we'll be in PJM

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West will decide whether it's an ACAP or an ICAP responsibility. ACAP is an operating reserve criteria whereby, going into the next day, one has to have a certain amount of generating resources available, and there's a percentage that that determines, or their region can come under ICAP, which is, on an annual basis, one shows that one has rights to capacity, again, based on a certain percentage.

Q. What happens if this Commission makes a determination that the proper reserve margin or reserve requirements for generation mix of Kentucky Power is different than what PJM determines? Who wins in that determination?

A. I think the way that works practically is that the Commission, from a recovery standpoint, could determine how much generation could be used in the calculation of rates in Kentucky. The AEP, if - let's take a hypothetical. Let's say that the Commission said we couldn't have any more than a 10 percent reserve margin and PJM said we have to have 12 percent. Then there would be two percentage points of reserve margin that we probably would be asking to get treatment for in a rate review but may or may not get it.

Q. Well, you just hedged that at the end. Assume that this Commission finds that certain PJM expenses are unreasonable. Can this Commission disallow recovery of those unreasonable expenses in a ratemaking process?

MR. OVERSTREET:

Your Honor, I hesitate to object, but he's going down the same road. He's asking legal questions that are . . .

MR. KURTZ:

Well, let me respond to this.

MR. OVERSTREET:

. . . briefed before the Commission.

MR. KURTZ:

These questions go to the heart of whether or not the Commission should cede control over a substantial part of transmission, generation, and ratemaking authority that has kept rates so low in this jurisdiction historically, and I understand that they border on legal questions, but I would think that, if there are answers that the company or PJM want the Commission to have in making its decision, they would attempt to answer them. These are questions I would be interested in and I think are relevant in making this determination.

CHAIRMAN HUELSMANN:

We're going to overrule your objection. I think these do go to the heart of the matter, and Mr. Baker has been around for 30 years, and he certainly knows this industry as well as anyone, or at least I would take judicial notice of that matter. So, if you could, rephrase that, Mr. Kurtz, or restate it, and you answer to the best of your ability, Mr. Baker.

Q. In the ratemaking process in Kentucky, can this Commission disallow as unreasonable expenses that are approved by PJM? Let me rephrase that. Assuming that Kentucky Power incurs costs through the PJM process that this Commission finds are unreasonable, can the Commission disallow those costs in ratemaking?

A. Well, my experience is that commissions, although they tend to be very fair, we have had places where they have disallowed costs that we believe were prudently incurred, and then the question is, and this gets to the legal argument, is it something that's preempted as a result of being a charge that comes through the tariff or not, and that's the part that would have to go through whatever legal process it would have to go through. I would hope that ultimately the Commission would find that this was a good action on the part and wouldn't need to disallow such costs.

Q. If we were only talking about transmission costs, that would be a fairly limited area of preemption, and I say "limited," 10 percent . . .

A. Uh-huh.
Q. . . . of Kentucky Power's revenue requirements or thereabouts or some amount of money, but, when we start getting into the generation costs and reserve margins and dispatch costs and redispatch, now, we're starting to get into a vast majority or a substantial portion of the utility's costs, aren't we, that could be subject to preemption if this transfer is approved?
A. I guess I don't necessarily see it the same way as a large measure of the costs. We don't think congestion is going to be a significant cost to the AEP System. When we look at reserve margins, the kind of reserve margins that they are looking at in PJM are not inconsistent with the kind of reserves that we've believed were needed on the AEP System to maintain reliability and economic supplies. So I'm not sure that I agree or I don't agree with the contention that that has a large dollar impact on the company.
Q. Let's talk about the hourly and the day-ahead energy markets that PJM will operate.
A. Okay.
Q. Right now, I understand that those are voluntary; isn't that right? You can choose . . .
A. Yes.
Q. . . . to sell into those markets or you can choose to

self dispatch. You can choose to do bilateral transactions. So the hourly and the day-ahead PJM markets right now are voluntary on the utilities?

A. Yes.

Q. Okay. With a filing at FERC, would PJM be authorized to make those mandatory, if FERC were to approve that? In other words, tell AEP or any utility that you must sell into the PJM markets and that you must buy your requirements back from the PJM markets. Is that a possibility?

A. I believe we went down this path before, and there is always a possibility that someone, for example, the Regional Transmission Organization, requests more authority than they have today. I think it's unlikely. I think it would be a very difficult process for them to get the necessary approvals to do that. So everything is a possibility but I don't think a probability.

A. Okay. In that process that you don't think is probable, the Commission in that process would simply be an intervenor; wouldn't it? It wouldn't be a decision maker. It would be an intervenor at FERC?

Q. It would be an intervenor at FERC, and I would think it would be probably involved in any actual court determination, after the fact, as an active participant.

MR. KURTZ:

Thank you, Mr. Chairman.

CHAIRMAN HUELSMANN:

Thank you.

MR. RAFF:

Your Honor, before we do redirect, I have a few more questions that we . . .

CHAIRMAN HUELSMANN:

Well, I think we need to proceed with the order, and we'll allow you to come back.

MR. RAFF:

All right.

CHAIRMAN HUELSMANN:

Mr. Little, do you have any questions?

MR. LITTLE:

We have no cross, Your Honor.

CHAIRMAN HUELSMANN:

Okay. Mr. Overstreet, do you have any redirect? And we're going to allow the Commission to proceed later, but I think we need to go in order.

MR. OVERSTREET:

Yes, Your Honor. First of all, I might like to show the Affidavit of Publication to counsel and then have it entered as Exhibit 1.

CHAIRMAN HUELSMANN:

Has everyone seen AEP No. 1, the notice? Any objections to it?

MR. KURTZ:

No.

CHAIRMAN HUELSMANN:

It will be admitted then as AEP No. 1.

AEP EXHIBIT 1

MR. OVERSTREET:

Your Honor, could we have about five minutes to chat? He's been on the stand about an hour.

CHAIRMAN HUELSMANN:

Well, would you prefer that Mr. Raff asked his? How long are you going to be, Mr. Raff?

MR. RAFF:

I've got a few questions, five minutes, maybe ten minutes.

MR. OVERSTREET:

That would be . . .

CHAIRMAN HUELSMANN:

Do you want him to go ahead for ten minutes?

MR. OVERSTREET:

That would be fine.

CHAIRMAN HUELSMANN:

Then we'll take a recess and go from there.

RECROSS EXAMINATION

BY MR. RAFF:

Q. Mr. Baker, you were asked about the status of the approval process for your Virginia affiliate. You also have two affiliates that operate in the state of Ohio; is that correct?

A. That is correct.

Q. Is there an open proceeding with the Ohio Commission regarding the transfer of the transmission assets of those two utilities to PJM?

A. In Ohio, as part of the restructuring plan, there was a transmission component, and it dealt with participation in RTOs. Originally, when we were looking at our RTO participation, we had indicated our plans were to join the Alliance RTO, which later was rejected by the FERC as an RTO. At the time they issued Orders on the separation case, I'll call it, the deregulation case, they never formally ordered approvals or disapprovals of people's choices regarding RTOs. The rest of the areas that needed to be dealt with were ordered on. Those were not and just nothing happened with it. When we made the decision to pursue PJM participation rather than Alliance participation, we felt it was the appropriate action to update the Ohio Commission on our plans. We filed with them similar to how we had here, telling them what our plans were and explaining why. They recently put out an Order saying that there was a lot going on at a federal level, and they were not ready to provide us an Order on the transmission transition case, I'll call it, and so we don't know when they will act or if they will act, just as they never pursued anything from the Alliance standpoint.

Q. You said that you made a filing with them to update them. Is the purpose of that filing to get some specific approval of your transfer of transmission assets to PJM?

A. As part of the legislation, I believe that we were told we needed to file for approvals of transfer of control. As I said, we had given them a plan in regards to the Alliance, and we just wanted to make sure we had covered the bases that we needed to cover in Ohio so it informed them of our plans.

Q. I'm still a bit confused.

A. Okay.

Q. Was your filing to just inform them of your plans or to get an Order back from the Ohio Commission approving the transfer of the transmission assets to PJM?

A. We hoped we would get an approval from them, but, as I say, we hadn't gotten ultimately an approval on the last one, so I didn't know whether they would act or not.

Q. All right, and the Order that was issued by the Ohio Commission basically held the proceeding in abeyance; is that correct?

A. I think that would be a fair interpretation.

Q. And the reasons cited by the Ohio Commission were, I think, the uncertainty regarding when you might get final FERC approval of joining PJM as well as outstanding unresolved issues with respect to the standard market design that is being proposed by FERC? Is that fair?

A. I don't have the actual Order in front of me, but I believe that that's probably pretty close to what they said.

MR. OVERSTREET:

Your Honor, if it would be helpful, we would be happy to supply a copy of that Order to the Commission and Staff.

CHAIRMAN HUELSMANN:

I think we've got a copy of it. Does everybody have a copy of that Order? I think we need to put it in the record, though, and mark it as "Staff . . ."

MR. RAFF:

If the applicant could. I've lent my copy to somebody else and haven't gotten it back, so . . .

MR. OVERSTREET:

Excuse me, Mr. Raff. I don't have it here with me today, . . .

MR. RAFF:

Sure.

MR. OVERSTREET:

. . . but I would be happy to file it.

MR. RAFF:

That will be fine. Thank you.

Q. Mr. Baker, the restructuring statute in Ohio that you referred to, that mandates that the utilities operating in the state of Ohio transfer the transmission assets that they own to an RTO; is that correct?

A. I don't remember. I remember the process. That's something we could verify and get to you, but I'm not sure whether it was part of the process or it's actually in the statute. I can check.

Q. If it . . .

CHAIRMAN HUELSMANN:

I think that should be made a Data Request, and what we've done, for the people that haven't been here before, is we ask that to be completed within 14 working days and, if you can't, call and we'll give an extension and, if we need it earlier, tell

us, but we'll consider that a Data Request.
Q. Mr. Baker, if it's not in the statute, I'm not sure I understand what you mean by "as part of the process."
A. It was clear to us that, from both the Commission Staff as well as the various intervenors in Ohio, that they felt RTO participation was a critical aspect of going forward with the plans for deregulation and made that a part of any settlements associated with moving toward the deregulation in Ohio, but what I'm not sure of - I apologize, but we do serve in 11 states and sometimes I get, you know, various - what's exactly in each state law, it's better if I look at it before I answer it.
Q. I understand. The two utilities that AEP owns that operate in Ohio is Ohio Power and Columbus and Southern Power; is that correct?
A. That's correct.
Q. Whether it was by statute or by part of your agreement regarding restructuring, I assume what you're talking about is either an obligation - I guess it would be an obligation to transfer to an RTO the transmission assets owned by Ohio Power and Columbus & Southern Power. Is that . . .
A. The functional control over those transmission assets.
Q. Okay. You did not agree, or did you agree or commit in Ohio that you would transfer functional control of the

transmission assets owned by Kentucky Power?
A. As part of the process, we settled and the expectation in that settlement was that we would be moving all of AEP's assets, that they could not be separated. At the time that we entered into this merger commitment and the commitments around these states, we did not have a feeling from any of the states that they opposed AEP's participation in RTOs and that has appeared in some states since we made those commitments.
Q. You're familiar, are you not, with the Midwest ISO?
A. Yes, I am.
Q. Would it be fair to say that some states have new found concerns because of recent FERC decisions overturning basic agreements that the transmission owners entered into when they joined the Midwest ISO?
A. I've heard - there are a lot of reasons why people have changed their opinions, but I think underlying it tends to be the increased responsibility that RTOs are expected to take on specifically as a result of the SMD process. The standard market design process seems to be the underlying issue around various parties no longer thinking RTOs may be as good a vehicle as they once were.
Q. And, for every increase in responsibility taken over by the RTO, there's a corresponding decrease in

responsibility performed by the transmission owner and what would otherwise have been subject to state jurisdiction; is that fair?
A. I don't know whether it's everyone, but certainly some of them.
Q. Okay. Back to the Ohio situation, are you saying, then, that the commitment that you made in Ohio as part of the restructuring process was that you would transfer control of all transmission assets, including those of Kentucky Power, to an RTO?
A. When we entered into the agreement, it was our expectation that we would be transferring all of AEP's assets in the East to an RTO.
Q. Was there any reservation in any of the documents that indicated that this was, you know, subject to approval by possibly Kentucky or other states?
A. There was nothing in the documents like that; no.
Q. Okay. In response to a question from Ms. Blackford, you indicated that one of the benefits that you thought from RTO membership was an expectation that incremental sales would be made and that the profits from those sales would be flowed back to AEP Pool members; is that correct?
A. Yes.
Q. With the deregulation of generation in Ohio, you've

recently received approval from the FERC to restructure your Pool Agreement from five members down to three which excludes the two Ohio members; is that correct?

A. We have received permissive approval to do that.

Q. All right, and, with a three-member Pool and the, in effect, deregulation of the Ohio generation, is the expectation about these incremental sales going to provide a greater benefit to the unregulated entity that owns the Ohio generation versus the regulated utilities that comprise the three-member Pool and still own their generation?

A. The question is premised first that we will perform the separation and remove the two Ohio companies from the Pool. That is not an action that we now - we're not sure that we will be doing that at this point. If, in fact, we were to go forward and do the separation and remove the two companies, there would be benefits both to the two companies in Ohio and to the remaining three companies in the Pool as a result of being able to make incremental sales. They just would not be shared. They would be the surplus generation of the three-member Pool would, we believe, have benefits, and there would be benefits that would flow to the two companies in Ohio as a result of their incremental sales.

Q. Would it be fair to assume that there would be a lot

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more incremental sales from the unregulated Ohio generation than from the regulated generation of the other three Pool members?

A. I can't speculate on that, because I don't know what the - if we went down that, how much there would be done on a bidding into the PJM Pool versus bilateral transactions that would be entered into by the Ohio companies, I just can't speculate on that.

Q. All right. One of the other benefits that you mentioned to Ms. Blackford was the ability to buy power at prices that were lower than Big Sandy by bidding Big Sandy into the PJM market and then buying power? Is that basically what you said?

A. I believe what I said was that there may be instances in off-peak times where that may become available to us.

Q. Let's explore that a little. I'm having some difficulty understanding what type of circumstances would lead to those types of instances. My recollection from the Data Response, and I believe it was Kentucky Power's Response to the PSC's Supplemental Request, Item No. 10, that was updated, filed on March 12, on the second page it's entitled "Data Obtained From Platt's POWERdata Database" that shows the production costs for the utilities that comprise the

AEP East companies and then the PJM companies. Looking at these figures, it would appear that the production cost of Kentucky Power is the lowest of any of the utilities shown on this schedule. Is that true?

A. The information here is annual values and, yes, it is the lowest annual average number of all of these.

Q. Okay, and, under the AEP Pool Agreement, if Kentucky Power's generation is running and it has load to be served, that load is allocated or assigned the cost of its own generation; is that correct?

A. At least some of the generation will be assigned. Under the Pool, we do what's called the redispatch, and we look at all of the generating assets and their costs, and then you strip out those costs, those generating assets, that are used for off-system sales, and those are assigned to the off-system sales, and then the remaining generation in each company goes first to serve its own load, and then, after meeting its own load, if they have surplus still, it's assigned to serve primary energy for delivery to other Pool members who didn't have enough generation left in their own portfolio to meet their load.

Q. Okay. So I guess that's what I'm trying to understand then. With those requirements under the AEP Pool, in what circumstances, considering the price of Kentucky

Power's generation vis-a-vis the price of the other Pool members' generation, under what circumstances Kentucky Power's generation would not be assigned to either meeting the load of Kentucky Power or another Pool member but would be available to be sold into the PJM energy market?

A. Okay. Again, let me go back to what I said. I said that it could happen in certain off-peak times, and, under their - if you look hour by hour on the AEP System, there are different units that are effectively the unit that would otherwise not be loaded just to serve AEP's native load but has been brought on to make system sales. Okay? It varies. If you go to off-peak periods during the spring, we've had times where the marginal unit was a nuclear unit, and we've actually had to sell nuclear generation because we had to have units on to meet load requirements and your marginal production cost is down that low. Big Sandy is above that. So there are certain times when you would not otherwise run Big Sandy because of a marginal decision and, at that point, if you could bid that in and purchase at a price that's cheaper, the benefit would come to the AEP Pool.

CHAIRMAN HUELSMANN:

Mr. Raff, it's ten-thirty. I think it's time for us to take a break for about 15 minutes, if you don't mind.

MR. RAFF:

That's fine.

CHAIRMAN HUELSMANN:

Let's come back at a quarter till eleven. We'll stand in recess until then.

OFF THE RECORD

CHAIRMAN HUELSMANN:

Okay. The record should reflect we're back in session. It's about ten forty-seven. Just one small announcement. Apparently, someone was in the back here in the Hearing Room, and this afternoon at one o'clock there is another hearing there. Directly across the hall, a little to the right, is a conference room which you're welcome to use and if any other body wants to caucus without, I assume it was AEP - I don't know this - there's also the conference room upstairs directly across from my office that you can use, if you need to, after one o'clock.

MR. OVERSTREET:

Thank you.

MR. RAFF:

It was AEP, because it was on the web and I was listening to them in my office.

MR. DUFFY:

We only said nice things about you, though, Richard.

CHAIRMAN HUELSMANN:

Okay.

MR. RAFF:

That was a joke.

CHAIRMAN HUELSMANN:

Mr. Raff, I think you're still questioning.

MR. RAFF:

Yes.

Q. Mr. Baker, I think you were explaining the instances or circumstances related to the instances when Big Sandy would not be needed on the AEP System, and you've made reference to certain times when the marginal cost of power is set by the AEP nuclear units, and my understanding is there are two units at Cook that have maybe 2,100-2,200 megawatts of output. Is that about correct?

A. Let me try to clarify and then directly answer, I think, the question. What I indicated was not that the Cook Units would set the price. I said that there have been times where the Cook Units were the marginal production units. This is very off-peak periods. It

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doesn't happen very often, but it has happened where we actually had to go out and make sales in the off-peak in order not to unload the Cook Units. Now, what obviously isn't clear, and it can get pretty confusing, is that there's only 2,100 megawatts approximately at the Cook facility, and AEP's load never gets, let's say, below 10,000 megawatts. It may get a little below, but that's a fair one to use. If you have 10,000 megawatts of minimum load generation on the rest of your generating units so that you have no choice but to have that generation on, you then ramp up each unit above its minimum load. So, in the rare cases, when you are down on minimums, everybody is at minimum load, the next incremental unit is Cook, and, as you put more load on and increase generation to meet it, your marginal production unit moves up the cost stack, and so, you know, in the very rare case, it's Cook. The next unit in production cost is a little less rare than Cook, and then, when you get to the highest cost units on the system, those are the marginal units most often, and, again, you have to think of these numbers as we see them here on this sheet that you pointed me to, the POWERdat Database. These are average numbers for the whole company, for the companies listed here. In Kentucky, we happen to have just the Big Sandy and the purchase from Rockport. So those numbers aren't that far apart. In the case of other companies, they may have ranges for nuclear units down to $8 a megawatt-hour to gas-fired units that are $35, and the average comes out. So what you're looking for are those times when you can access the lowest cost generation of a company.

Q. Well, the Indiana and Michigan affiliate is the only one that owns the nuclear; is that correct?

A. They're the only one at AEP that has nuclear; yes. I'm sorry. They're the only one in the AEP East that has nuclear.

Q. Okay. Well, could you - I mean, would it be fair to say that these limited instances that you're referring to would occur, you know, a couple of hours a year.

A. I don't know how often it will happen. The other way that Kentucky can benefit is there can be times where it's actually cheaper if Kentucky is relying on the Pool where incrementally we purchased against another unit on the AEP System and the benefits of that flow to Kentucky rather than buying energy from the Pool that may have a more expensive cost. How many hours those events happen, I don't know.

Q. Would it be fair to say it's fairly few?

A. That's hard for me to say. If "few" means three hours,

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and I'm not being cute here, if it means three hours out of 8,760, I think it's probably likely. If we wanted to say, "Is it going to happen 25 percent of the time?" I would probably say no.

Q. Okay. We had asked some questions about your joining PJM being tied to a commitment made at FERC to join an RTO and that commitment was made in a proceeding in which you sought approval of the merger of what is now referred to as the AEP East companies with the Columbus and Southern companies; is that correct?

A. Central and South West.

Q. I'm sorry. Central and South West, you're right.

A. I do the same thing.

Q. In addition to the need for approval by FERC for that merger, you also needed approval of the Securities and Exchange Commission; is that true?

A. Yes, that's correct.

Q. And the SEC issued an Order approving the merger, but then that Order was overturned by the D.C. Court of Appeals; is that also correct?

A. Not being a lawyer, I'm not sure "overturned." I know it was sent back to the SEC for them to review the Order that they had.

Q. They found some deficiencies in the original SEC approval Order. Would that be fair to say?

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A. I think that would be a fair representation.
Q. All right, and the Court remanded it back to the SEC. I think it has been over a year ago; is that correct?
A. Yes.
Q. Has the SEC issued a further Order either granting or denying merger approval?
A. No, they have not.
Q. All right. Do you have an expectation that an Order will be issued by some definitive date?
A. I would hope that we would get an Order sometime soon, but, at this point, I have no expectation of when that might be.
Q. Okay. So SEC has not indicated that they were on a specific timetable to issue a further Order?
A. Not that I know of.
Q. All right. Until such time as the SEC approves the merger, is the merger subject to be undone?
A. Yeah. That's one of those things that I haven't quite figured out how one unscrambles an egg, and I assume that legally it could be undone. I don't know how that works. I've tried to think it through and haven't quite figured out exactly what that would entail. On the other hand, it's our expectation that the issues that the Court raised I think could be easily addressed by the SEC with information that was on the record at

the SEC when they gave us the approval.

Q. But apparently the SEC either feels differently or doesn't want to make that decision?

A. I have no real input as to what the SEC's thinking is.

Q. With regards to the merger commitment that you made at FERC with respect to joining an RTO, you mentioned that you had recently filed a status report at FERC in which you discuss the recently enacted statute in Virginia and the status of the proceedings that you filed at other states and that report also suggests that the FERC does have the legal authority to preempt any state approval process or any state law that might hinder your joining an RTO, but you urged FERC to not exercise that authority at this time and to, as a first step, get all the parties together in an effort to open a dialogue to see whether the differences amongst the states can be amicably resolved. Is that a fair summary of what your filing says?

A. The only part that I would like to review, and, if somebody has a copy, you know, I can review it very quickly, is the representation about FERC's authority and how we characterize that. The rest of it, I would agree with you; that we represented that we thought it was best for them not to exercise any authority that they had and instead met with the states and tried to resolve the differences associated with RTO rather than creating the potential legal conflict which we've been trying to avoid between the federal agency and the state regulatory commissions.

Q. I don't have it here in front of me, but my recollection is that the report does quote from a provision of the Public Utility Regulatory Policy Act of 1978 regarding power pooling and the FERC's authority to preempt any state law or action that would otherwise hinder FERC's efforts to enforce or coordinate Power Pools.

MR. OVERSTREET:

Your Honor, if it would be helpful, we could simply provide a copy of that letter and it could speak for itself in the record.

CHAIRMAN HUELSMANN:

I think that should be a Data Request, but, if he can answer - but let's get it in the record.

A. I'm not sure I heard a question.

Q. I guess I'm asking whether that confirms, to your recollection, there was some references to FERC's authority under PURPA regarding power pooling arrangements.

A. As I say, I would prefer to see it.

Q. Okay.

A. I don't disagree that we referenced PURPA and talked about the provisions of PURPA. I'm not sure exactly what conclusions we drew from that, which is I think what you're suggesting, that we drew conclusions, and I can't remember exactly what that was.

Q. That's fair enough.

MR. RAFF:

With the request to introduce Cross Examination Exhibits 1, 2, and 3, I believe that's all the questions we have now for Mr. Baker.

CHAIRMAN HUELSMANN:

Does anyone have any objections to the PSC's 1, 2, and 3? No objections. They'll be admitted.

PSC EXHIBITS 1, 2, 3

CHAIRMAN HUELSMANN:

Before Mr. Overstreet starts, I just want to make one short announcement. The trade press is reporting that Warner signed that Virginia Bill yesterday. So that's what the status of that Bill is. Mr. Overstreet or Mr. Duffy, which one? Mr. Overstreet?

MR. OVERSTREET:

I believe I'll take it, Your Honor.

REDIRECT EXAMINATION

BY MR. OVERSTREET:

Q. Mr. Baker, Mr. Raff was questioning you about the approval by the FERC of the merger between American Electric Power and the old Central and South West Corporation. Were you part of that process?

A. Yes, I was.

Q. And were you involved in the negotiations with FERC staff and the various intervenors?

A. Yes, I was.

Q. And are you familiar with the positions that the parties took in those negotiations and then also before the various proceedings before the FERC?

A. Yes. The positions they took was that they believed that they thought it was appropriate to make sure there was no transmission market power, that AEP turned control of their transmission assets, functional control, over to an RTO at that point, and it was really FERC policy, at that point, that mergers would be conditioned upon joining RTOs.

Q. And you said that they believed that it was necessary that AEP transfer the transmissions assets to RTOs. Who did you mean by "they"?

A. "They" being - mainly the staff took a very active role, but it was not only the staff; it was many of the intervenors as well.

Q. Was it your understanding that, to obtain approval for the merger, that AEP would be required to make the commitment that it made?

A. Yes, and I think it was proven out in the condition which actually went further and actually set a date where we needed to be in a fully functioning RTO, which was an enhancement, I'll say, or an addition to the commitment that was made as part of the settlement process.

Q. Mr. Baker, I believe it was Staff Cross Examination Exhibit No. 1, which was the Initial Decision in the merger case - Mr. Raff asked you some questions about that. Was there, in fact, a subsequent Order entered by FERC?

A. Yes, there was.

Q. And, if I could direct your attention to Commission Staff - its 1st Set of Data Requests, Item No. 15.

A. It's my understanding that, under the Response, Subpart (a), that is the Order in the merger which accepted or approved the merger and set the condition about RTO participation.

Q. And that was the FERC Order you referenced in your prefiled testimony?

A. That's correct.

Q. Okay. Mr. Baker, Mr. Kurtz was inquiring of you about a 50 basis point return on equity. Could you explain to the Commission how that will affect Kentucky customers?
A. Yeah. The impact is actually on wholesale customers, what will result from our request for new rates for network service. It is true that we would have to pay whatever that approved rate is to PJM for delivery to all of our customers, but, in turn, we would get back those dollars as a credit. So there would be a wash between what we paid and what we received back from PJM. So the impact is on wholesale customers who may, in fact, have to pay an additional value.
Q. And, Mr. Baker, you were asked about the status of proceedings in Virginia and Ohio. Does AEP presently have an application before the Indiana Commission concerning transfer of functional control of transmission assets to PJM?
A. Yes, we do.
Q. And could you brief the Commission on the status of those?
A. Yes. Similarly, we filed in Indiana requesting approval and that case is on a slightly slower procedural schedule than there was here. It appears that the hearing will be held in mid-May. In that

case, the Staff of the Indiana Commission came out in support of our transferring the assets to PJM.

Q. Mr. Baker, you were asked about negotiations with the Ohio Commission in connection with the deregulation, and you were asked a series of questions about those. At the time of those negotiations and the agreement made by AEP, was KRS 278.214 the law of the Commonwealth?

A. No, it was not, as I understand it.

MR. OVERSTREET:

Okay. That's all we have, Your Honor, at this time.

CHAIRMAN HUELSMANN:

Thank you. Mr. Raff, I think procedurally we need to go back to you again. Any recross?

MR. RAFF:

No, Your Honor.

CHAIRMAN HUELSMANN:

Ms. Blackford?

MS. BLACKFORD:

I have one further question with reference to 278.214.

RECROSS EXAMINATION

BY MS. BLACKFORD:

Q. If you become a part of PJM and there is a pro rata shutdown for some reason, how does that impact your obligation to serve in Kentucky? I guess the other side of that question would have been, would it be conceivable that there would be a PJM emergency shutdown that would require a pro rata curtailment that would not have impacted the Kentucky system were it separate?

A. I would like to answer the second one. It just frames it, I think, a little easier. We are in a situation today where we have functional control over our transmission system, and, in emergency situations, we will have to make curtailment decisions, and we have plans that outline how we will do that. I do not see that those will change as a result of joining PJM. I believe that they will not be curtailing things in Kentucky, for example, to make sure power stays on in Maryland. They will treat it very much like we would do today and would have in the future. If we retain functional control, we would determine the most prudent course of action in order to maintain the highest level of reliability on the system possible.

Q. I guess, then, my question becomes what is the system?

Does this permit the system outside the AEP territory to impact what happens within the AEP territory, or are you saying to me that the physics of the situation are the same regardless and that AEP might well have been impacted anyway?

A. I'm saying that AEP is impacted anyway as a result of actions taken by other parties because that's just the nature of it. I believe that there will be less of an impact as a result of being in an RTO and having them look over the entire grid in making decisions as to who gets access and how much access is given to various participants. So the likelihood of a problem we would hope would diminish as a result of a broader look at the transmission system.

MS. BLACKFORD:

Thank you. That's all.

CHAIRMAN HUELSMANN:

Mr. Kurtz?

MR. KURTZ:

No more questions.

CHAIRMAN HUELSMANN:

Mr. Little?

MR. LITTLE:

No questions, Your Honor.

CHAIRMAN HUELSMANN:

Any re-redirect?

MR. OVERSTREET:

No, Your Honor.

CHAIRMAN HUELSMANN:

May this witness be excused? Okay. Thank you, Mr. Baker. I assume that's your case.

MR. OVERSTREET:

Yes, Your Honor.

CHAIRMAN HUELSMANN:

Okay. The Attorney General, do you have any witnesses?

MS. BLACKFORD:

No.

CHAIRMAN HUELSMANN:

Any witnesses for KIUC?

MR. KURTZ:

No.

CHAIRMAN HUELSMANN:

Mr. Little has two witnesses.

MR. LITTLE:

Your Honor, PJM calls its first witness, Robert Hinkel.

WITNESS SWORN

CHAIRMAN HUELSMANN:

Thank you. Have a seat, sir.

The witness, ROBERT HINKEL, after having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. LITTLE:

Q. Please state your name and address for the record.

A. My name is Robert Hinkel. My business address is PJM Interconnection, 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403.

Q. Do you have before you what I will ask to be marked as PJM Statement No. 1?

A. I do.

Q. Was this testimony prepared by you or under your direction?

A. It was.

Q. Do you have any corrections or additions to offer at this time?

A. I do not.

Q. If I were to ask you the questions contained in your testimony today, would your answers be the same?

A. They would.

MR. LITTLE:

Mr. Hinkel is now available for cross.

CHAIRMAN HUELSMANN:

Have we decided on an order of examination of this witness? Everybody is looking at each other.

MR. RAFF:

I guess I'll proceed.

CHAIRMAN HUELSMANN:

Who wants to go first?

MR. RAFF:

I default.

CROSS EXAMINATION

BY MR. RAFF:

Q. Good morning, Mr. Hinkel.

A. Good morning, sir.

Q. Have you seen what's been identified as Staff Exhibit No. 3, the statute KRS 278. 214?

A. I have not.

Q. All right. If you could, take a minute and read that, please.

A. Yes, sir.

Q. Is it within your area of expertise to be testifying on the rules and conditions upon which PJM might require load to be interrupted when there are emergencies on a transmission system?

A. Yes, sir.

Q. All right. If Kentucky Power becomes a member of PJM,

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will Kentucky Power be able to give priority to its native load customers if there is an emergency on Kentucky Power's transmission system that could be alleviated by interrupting service to other than native load customers?

A. Under PJM's agreement, native load customers would take network integrated transmission service. They are on par with regard to interruption with those customers taking firm power. So those two are a single class in terms of interruption. All others could be curtailed to preserve service to firm power and to the network integration customers.

Q. When we talk about native load customers, we're talking about here in this case the customers served by Kentucky Power within its service territory as it provides service as a vertically integrated utility. When you refer to the term "network integrated service," are there other types of customers who could also take network integrated service?

A. In some cases, as outlined in this statute, wholesale customers, for example, would have the same level of service. They might also have firm power service, which is on par with network integration transmission service. So the two are synonymous from our perspective.

Q. And firm power service is a type of service that can be purchased by any entity that is transmitting power; is that true?

A. No. Firm power service is an alternate to network integration transmission service for serving load within a zone.

Q. Well, I'm trying to figure out, then, who can buy firm power service on Kentucky Power's system.

A. A wholesale customer who is serving load within the Kentucky Power system. Kentucky Power themselves may use firm service as an alternate to network integration transmission service to meet their firm load. Firm service is typically used in the Midwest to supply generation to load where bilateral transactions are used to provide that load in some cases. So it's an alternate to network integration transmission service.

Q. So only someone whose load is located within Kentucky Power's service territory could purchase firm transmission service from Kentucky Power?

A. No, sir. There could be a condition where a customer who is in another part of AEP's service territory, for example, could have firm power service across the Kentucky Power system to deliver energy to that load.

Q. So a customer in Ohio or Michigan within the territory of another of the AEP affiliates' territories could buy the firm transmission service, and it would then be entitled to the same priority vis-a-vis Kentucky Power if there was an emergency on the Kentucky Power transmission system; is that correct?

A. That's correct in the terms of the tariff. It seems like a most unusual situation to me. Most native load in any territory is served by network integration transmission service.

Q. I'm not sure I understand why you say it's something unusual; under the statute?

A. No. It's unusual in practice because the network integration transmission service customer is paying transmission service rates, and there's no logical financial reason in the PJM model for that customer to then subscribe to firm transmission service, pay an additional rate for that, because they still have exposure to the revenue requirement under network service. So they would actually be paying a second charge, in a sense, to get firm transmission service.

Q. Well, is the network integration service that the native load in Kentucky Power's territory would receive a higher priority of service than the firm power service that a wholesale customer might purchase?

A. No. They're at the same priority in terms of curtailment.

Q. So then, under the PJM tariff, if there was an emergency on the Kentucky Power transmission system such that load had to be interrupted, it would be done, assuming you get to the point that, by interrupting non-firm and other users and that still doesn't resolve the emergency, then firm service and network integration service would be interrupted on a pro rata basis?
A. That's correct.
Q. Can PJM require transmission facilities to be built within its footprint?
A. The provisions of the PJM transmission owner's agreements provide for a requirement that the transmission owner build facilities within the footprint as determined by our planning process.
Q. All right, and can you describe what that planning process consists of?
A. Certainly. Very broadly, it's a stakeholder-based process in which the transmission owner and PJM staff, along with potential new generation participants within the region and other stakeholders, including state commission staffs, consumer advocate staff, environmental interest groups, and the like, participate in reviewing two levels of studies, what we call a baseline study on an annual basis that looks out three

to five years and predicts those facilities required to meet anticipated load growth and shifts in basic load requirements on the system, plus any additional requirements that come about because of generation that wants to locate within the system. PJM collaboratively with the transmission owner and this regional transmission expansion planning group look at options to provide the upgrades required, and then the funding for those options is managed through a combination of transmission owner funding if the upgrades are purely required to meet load growth, for example, within the footprint or a combination of transmission owner funding and generator funding or participant funding where there's a combination of needs identified or, in the case of a generation interconnection alone, absent the need for any other reliability upgrades, the generator would actually pay the cost to upgrade the system.

Q. Is this process conducted on a discrete basis for each project, transmission project, that may be needed, or is this a process that's conducted to come up with a PJM-wide expansion plan?

A. It's a process that looks at the individual components, for example, the transmission owner requirements to meet load growth within the footprint, the individual

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generation projects themselves, but then it looks at all of that in an aggregate fashion by defining sub-regions and subareas where projects are logically grouped together so that we can optimize a solution and provide the maximum benefit at the minimum cost to all those participants. So the process begins with the fundamentals. New load growth in a specific area requires a reenforcement but goes out from that to encompass all of the generation that's going to be built in that particular area and the much broader look at overall PJM requirements in aggregate.

Q. And has this process been in place for some period of time?

A. I don't recall exactly, but it's been in place at least two years, perhaps as many as three now. Certainly, it was preceded by a broader transmission planning process in PJM that has gone on for a number of years.

Q. All right, and the stakeholder participation, is that from the very beginning of the process or, you know, when do stakeholders get the opportunity to participate?

A. Uh-huh. Throughout the process, in the sense of - I'll look at two pieces of the generation interconnection, for example. At the point in time when a generation builder decides they want to build in the PJM region, they enter a request in what we call a generation interconnection queue. At that point, they have to put up some advance money for us to do some studies, and, at the point where they identify a project, the general location and size of the project are made public through our web-based interfaces, and everyone who has an interest in that project can review the process as that project goes from basic concept through analysis and then finally potentially construction. Likewise, the annual review and baseline study work is done in coordination with a couple of committees within PJM, the Planning Committee, and there's a specific user group associated with the regional transmission expansion planning process. We do public meetings on an annual basis and follow up internal meetings and smaller group meetings with the participants in each area on an ongoing basis, typically quarterly, where the individual projects are reviewed and the long-term plans are reviewed for each area.

Q. And are these meetings conducted in the states where the affected transmission facilities are located?

A. We move around. Some of the meetings are conducted in the typical meeting venues that PJM uses in the Valley Forge area. The larger annual meetings, in a sense, are usually held in that location, but we also hold meetings and a lot of the working group sessions, for example, are held within the local venue, if you will, to get input from commission staff, from local participants in the process, and the like.

Q. All right. Being unfamiliar with the process, for example, if there is, say, a new generator going to locate in West Virginia and a preliminary determination made that there needs to be some upgrades to transmission facilities located in West Virginia and then, at some point in the future, after, you know, some analyses has been done, it's determined that the size of the upgrades in West Virginia should be smaller than originally anticipated but it will require then some upgrades in Kentucky, how would anyone in Kentucky know that, you know, this is now being proposed as part of this overall expansion plan?

A. Uh-huh. As a part of the planning process, when we're looking both at the baseline reliability plans and the plans for upgrades associated with new generation, we are very public with the option set that's under review, and, in many cases, we do one-on-one briefings, for example, with all of the state staffs on "These are the three options we're considering," and we have found, in a number of cases, that reenforcements don't necessarily want to be made in a most economical fashion around state boundaries. Your case is a very good one. There may well be many situations where a new generation addition is in one state, the optimum reenforcements are in the adjacent state or in an adjacent region, and we make sure that, as we look at those options, we have input from all the stakeholders in the region; not just in a particular area where the addition is being made.

Q. I also had a question for Mr. Baker on what was identified as Staff Exhibit No. 2. Have you had an opportunity to see that? That's the statute that has the number 278.212 and particularly Paragraph (2) of that statute.

A. Yes, sir.

Q. Is it your understanding of PJM's tariffs that they contain provisions that would not allow upgrades to Kentucky Power's transmission facilities, if needed for a new merchant plant, to recover the full cost from the merchant plant?

A. I believe that the structure in our generation interconnection process follows exactly this methodology, that, if the cost for system upgrades to connect and deliver that new generation to the network as a whole are only required because of the connection of that generation, those costs would be the responsibility of that generator.

Q. You said, ". . . to connect and deliver the generation to the network . . ." I'm not sure that this provision of the statute is limited to connecting and delivering. It says, ". . . upgrading the existing ... transmission grid, as a result of the additional load . . ."

A. And I interchanged the word "load" and "generation" from an engineer's perspective as a result of the additional generation. The generator is actually producing energy that it wants to deliver to the system. I think that's the equivalent of what the statute talks about as a result of the additional load caused by the merchant generating facility.

Q. Okay. I wasn't sure, by your term "deliver to the system," whether you were referring only to the facilities needed to make the interconnection between the generator and the existing transmission system versus upgrades to the existing transmission system.

A. Okay. No, sir. I mean both of those. We differentiate those costs in two places. We identify what we call system connection costs. They are always the burden of the generator, if you will. So, if something as simple as a connection to an existing substation is made, that cost is borne by the generator. If it's as complex as building a new substation, that cost is borne by the generator, and then, in addition, any costs that are required with regard to overall network upgrades, whether it's at the same station or another line or five stations remote associated with delivering that energy, are the responsibility of that generator if it's solely caused by the addition of the generator.

Q. All right, and that pricing methodology, then, does not encompass what is commonly referred to as rolled-in pricing?

A. I'm not familiar with the term "rolled-in pricing," so I'm not sure what that would mean.

Q. Well, it was my understanding that rolled-in pricing was, up until this point in time, the preferred pricing methodology that is used by the FERC in allocating costs of new transmission facilities to all of the users of the transmission system; not just a new generator that may be locating on the system even though the upgrades may be needed to accommodate that new generator.

A. Again, under our tariffs, if the costs are solely to connect and deliver that generation to the system, those costs are entirely borne by the generator.

Q. All right. So then your testimony differs from that of Mr. Baker's; does it not? Because I think he indicated that the determination of who would pay will be made more on a case-by-case basis considering an analysis of what facilities would be needed for the new generator.

A. Your hypothetical, to me, is one where the only upgrades that are required are upgrades on behalf of the generator. In the case where there were other requirements identified, what we broadly classify as reliability requirements, due to load growth or other system conditions, the picture gets a bit more complex, because we cost share then between the transmission owner and the generator in what we call a "but-for analysis." But for the addition of the generator, the transmission owner would have had to add facilities or upgrade facilities to meet growing load. So they share that cost. The transmission owner's costs to meet reliability requirements are reduced, and the generator's cost to interconnect are reduced, because he's providing overall benefit in meeting load growth. So it depends on your scenario. Your scenario where the upgrades are entirely to support addition of the generation, 100 percent of the cost is borne by the generator. Where some of it is reliability related, it's a little more of a mixed allocation of cost.

Q. Does PJM currently provide or have any plans to provide reliability coordination for non-PJM members?

A. PJM is today providing NERC reliability coordination for non-PJM members.

Q. So is that, then, in lieu of the NERC Security Coordinator?

A. PJM is - Security Coordinator and Reliability Coordinator are synonymous. The NERC community has flip-flopped between those two terms over the past couple of years. So we are the Reliability Coordinator for the classic PJM footprint, the Mid-Atlantic Coordinating Council. We are also the Reliability Coordinator now for AEP, Duquesne Light, Ohio Valley Electric Cooperative, and two other small generation control areas within ECAR.

Q. So then cooperatives and municipal systems receive their security coordination from PJM?

A. In those specific cases, yes.

Q. All right. PJM has recently filed with FERC a new Schedule 6 titled "Regional Transmission Expansion Planning Protocol," which incorporates transmission planning based upon economic justifications only as opposed to reliability justifications; is that correct?

A. Yes, sir.

Q. Could you describe the circumstances under which these expansions would be built and who would be required to pay for such expansions?

A. It's not really an area of my expertise. That filing came out of stakeholder process activity around the concept of developing an overall approach for so-called merchant transmission integration. I was familiar with the work in progress, but I'm not intimately familiar with the details of the filing.

Q. Okay. Do you know if Mr. Ott has more information on it?

A. I'm not sure if he does or does not.

CHAIRMAN HUELSMANN:

Would you like to have that as a Data Request, Mr. Raff?

MR. RAFF:

No.

CHAIRMAN HUELSMANN:

No? Okay.

Q. If you would, refer to Page 23 of your testimony, please. Towards the bottom of the page, you talk about the loop flow problems in Michigan and Wisconsin, and you say, "The resolution of this issue has an impact on Kentucky since, under some scenarios posed by Michigan and Wisconsin utilities, Kentucky utilities and/or customers would have to pay for loop flows on the Michigan transmission system but receive no concommittant payment . . ." Could you tell me how these payments would be addressed? I mean, whose tariff would collect these types of payments?

A. Well, it's an issue that arises out of the FERC July 31 Order, and one of those seams issues, as I point out here, is this issue that was raised by the Wisconsin and Michigan companies. It's currently under dispute resolution review with an Administrative Law Judge at the FERC. No final resolution has been reached, and it's not clear how, if ultimately the decision is that payments need to be made to the Wisconsin and Michigan companies as a result of that settlement, how they might flow through AEP's rates and cost structures. So I really don't know what the final outcome is. It's just an item that is still under adjudication, in essence.

Q. Well, is it your expectation that it will be something that would be included in the MISO's tariff?

A. I'm not sure why it would be included in the MISO's tariff.

Q. Well, I'm suggesting that only because that seems to be the regional RTO that includes some of the Michigan and Wisconsin utilities. I'm not sure how else Michigan and Wisconsin utilities would otherwise get compensation from a utility in Kentucky.

A. And I think that's going to have to be something that comes out of the end result of this proceeding with the

FERC.

Q. Okay. Is PJM participating in that proceeding?

A. PJM is a party to the proceeding; yes.

Q. All right.

MR. RAFF:

If I could have a minute, please.

OFF THE RECORD

Q. Refer for a moment, please, to Page 9 of your testimony, starting at Line 16. You say, "Qualified participants, by reducing load, can provide the same benefit to the grid as a generator that produces energy, . . ." Can you elaborate on how reducing load provides the same benefits as a generator producing energy?

A. Mr. Raff, I'm having some technical difficulty. My pagination isn't aligning with yours. Could you . . .

Q. Sure.

A. . . . point me to the question, and then I can . . .

Q. The question is, "What benefits are provided by the PJM wholesale energy markets?"

A. Okay.

Q. It starts, "PJM operates the . . ."

A. Uh-huh.

Q. ". . . largest and most liquid wholesale energy market in the country . . ."

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A. Yes. I'm in the right place now. Thank you.
Q. And it's about ten lines below that.
A. Uh-huh, and could you repeat your question, sir?
Q. Sure. If you could give a little elaboration on how reducing loads provides the same benefits to the grid as adding a generator that produces energy.
A. Certainly, and Mr. Ott can certainly go into the intricacies of how that plays in both the day-ahead and the real-time market, but, from an operations perspective, the maximum demand on the grid is a function of all that load, and, to the extent that we have a demand-side response that maximum demand on the grid is going to be reduced, that is very similar, operationally, to having additional generation to meet that demand had it been there. So that's the benefit provided. By reducing demand, if demand bids into the market and is callable at a certain price, reduction of 20 megawatts of load is the equivalent of adding 20 megawatts of generation to meet it.
MR. RAFF:
Thank you, Mr. Hinkel. I have no further questions.
A. Thank you.
CHAIRMAN HUELSMANN:
Ms. Blackford?

CROSS EXAMINATION

BY MS. BLACKFORD:

Q. Mr. Hinkel, as Exhibit F to your testimony, there is a market growth project budget. Is that a budget associated with a reliability expansion or what?

A. No, ma'am. This is the budget for the integration of the former Alliance companies into PJM. So it's our estimate of the project cost to modify all of the systems shown down the left-hand column to integrate the larger footprint those companies into the PJM overall structure markets, transmission operations, and the like.

Q. I see. So the referenced $35.4 million in the first column will be paid by AEP or is that by everyone in the Alliance companies that is expected to be integrated?

A. The latter. The costs are the total expense portion of the project, and, under our Implementation Agreements with the companies, they're each allocated a portion of that cost.

Q. And can you tell me what portion of that has been allocated to AEP?

A. I can't off the top of my head, but the formula in the Implementation Agreements was based upon the integrated annual load of the companies the prior year. So it was a pro rata share among those four companies.

Q. And to what does the capital column refer?

A. Under PJM's accounting processes, when we do an implementation of new systems and software, our general accounting guidelines require that portions of the project be expensed and portions of it can be capitalized. That column breaks out the capital portion of the projects which is not the direct responsibility of these companies during the implementation process. Those capital costs, estimated at $62.6 million, would be recovered over a three to five year life once the market integration is completed from all of the PJM member companies under our administrative fees.

Q. The MISO/PJM Common Market will ultimately carry a same tariff? Is that what I'm reading? I'm not quite sure what I'm reading about the through and out tariff or how the Common Market will be an advantage. Could you explain that to me a little better?

A. I can give you my conceptual understanding, and we need to talk to some rates and tariff folks if we want to go into more detail, but, as the companies have joined PJM and as a part of our filing in December, the transmission owners proposed new rates that provided a single through and out rate, a single rate at the

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border of PJM, if you will, and de-pancaked, removed the pancaking rates between companies within PJM. Midwest ISO has done the same thing within their tariff filings for their footprint. Again, as part of the July 31 Order last year, the FERC required that a single through and out rate be developed between the two RTOs so that we would remove, if you will, that seam or that pancake between the two RTOs. That rate proceeding is the subject of a FERC rate process that's running right now, but ultimately it should result in a single through and out rate for the entire PJM and Midwest ISO footprint.

Q. On Page 4 of your testimony, you refer to, at Line 4, PJM's use of a security-constrained economic dispatch coupled with voluntary energy markets. Can you first define for me what a security-constrained economic dispatch is?

A. Certainly. We gather a significant amount of data on a very high speed basis from all of our member companies, put that into a model that represents, for example, the chart in front of us, AEP's electrical system along with the others, and then solve that model to create what we call a state estimator solution. It gives us a view electronically of the flows on the entire PJM system. Then, from that, the security-constrained economic dispatch is the process that goes through using the participant bids into the marketplace and the current conditions of the system, load, generation, and the like, to determine what the next incremental generator is to meet load and set the costs at that. The security-constrained part of it means that, in doing so, it ensures that no facility is going to be overloaded either in real time or in the event of the loss of a facility.

Q. Does the combination of the voluntary energy market refer to what I was discussing earlier concerning the fact that the companies have to voluntarily bid their generators in?

A. That's, in general, what that's talking about; yes.

Q. At Page 6 of your testimony, you're discussing the fact that PJM prevents any undue influence over the operation of the bulk power facilities or markets in the PJM region. Would PJM consider the service of native load at the expense of service to wholesale market the exercise of undue influence?

A. Could you repeat the question to make sure I got it correct?

Q. Sure. Would PJM consider the service of native load at the expense of service to the wholesale market the exercise of undue influence?

A. I don't think that's undue influence. Serving native load is the highest priority, if you will, of transmission service. Did I . . .

Q. At Line 12 on that page, you reference that "Changes to the PJM Operating Agreement (which includes the energy market rules) require approval by the Members Committee." Now, that is a committee comprised of all who belong to PJM?

A. It's a stakeholder committee; yes.

Q. Is that a weighted committee?

A. Yes, it's sectorial voting. Each sector has a weighted vote, so it is a weighted vote approach.

Q. Who is the PJM Board of Managers?

A. The PJM Board of Managers is an independent Board that's elected by the members. They serve three year terms that are a rotating term, but they are completely independent. They have no interest in any of our participants. From a background perspective, they range from economists to senior business people, financial people. There's a former state regulator on the Board. So it's a very broad mix of characteristics but completely independent.

Q. On Page 10 of your testimony, you're referencing, at Line 12, that LMP encourages construction of new generation to alleviate constraint. Is there ever a point where the question comes between should there be new generation to alleviate constraint or should there be new transmission and, if so, how is that determination made?

A. And actually the mix involves the drivers, if you will, the price signals to build new generation, the cost to build new transmission to alleviate a congestion situation, the potential for demand-side response, and, more recently, some preliminary discussion within PJM of distributed generation as another alternative. So, from our perspective, the price signals that are generated both daily and then long term in the LMP-based market provide the signals to participants in those areas and then participant response may involve a generator deciding that a particular location is advantageous to build a new plant because of the price, or it may involve a wholesale customer or a large industrial customer in states where they have retail choice and they can do that and, with their load server, reduce load, for example, to avoid that high cost. So all those options are essentially in play, and they're being driven through both the planning process and the market signals.

Q. On Page 11 of your testimony, at Lines 16 and down, you're discussing the FTR auction and how it will create a more robust market, and the language I'm concerned with is ". . . and provide additional opportunities for load servers to obtain FTRs to meet their portfolio needs." Should I take from that any implication that it is possible that the assigned FTRs on an annual basis are not sufficient to allow a load serving entity to meet its native load needs?

A. I believe, in covering all the possibilities, that is a possibility. Mr. Ott would be more well versed in the likelihood and other mitigating approaches.

Q. On Page 13 of your testimony, you discuss the regional planning process, and I take, from that, the PJM can tell a transmission owner it must upgrade; is that correct?

A. That's correct, and it actually is a provision of the transmission owner's agreement that they are, in essense, the builder of last resort. They are required, within their footprint, to build if the process says some new construction is required.

Q. "They" being the individual utility rather than the PJM?

A. Yes.

Q. All right. What are baseline upgrades referred to there?

A. Baseline upgrades are part of what I discussed with Mr.

Raff. It's the concept that, on an annual basis, we look out three to five years at load growth and the shifting of load within the footprint and do some analysis with the transmission owners to determine if there are upgrades that are required just to meet load growth, for example. They would become part of the baseline requirements.

Q. On Page 24 of your testimony, beginning at Line 12, you say, "In bundled states the Common Market will allow for more efficient dispatch of generation which will result in lower costs to consumers." Can you elaborate on that for me, please?

A. Certainly, and, by example, I might go back to the discussion earlier with Mr. Baker around the economics of an AEP or a Kentucky Power based unit versus other AEP units in the market, in general. In those situations where you have a larger market and you're in some sort of a transition period, whether it's a light load period or a period where you have maintenance on one part of the system and not the other, the larger market gives the portfolio manager, if you will, whether that's the incumbent utility serving their own load or an alternate supplier serving load or a wholesale customer, more options to meet that requirement. There's more units available that they could do either a bilateral transaction with to meet their requirement or they have the broader spot market with a lot more units available. A good example might be the case where the next dispatchable unit that a company has to meet their own load might be a combustion turbine fired with very expensive fuel. It's a very high-cost unit, whereas, if they could look in the broader market, they might find a steam unit that's fired by coal that is at a lower incremental cost and be able to either buy that on the spot market or do a bilateral deal in the marketplace to take advantage of that.

Q. Would I be fair in saying that this is a concept statement that is directed more at utilities that have a broad spectrum of generation production cost in their system rather than being a fairly low-cost power producer with a very large margin of baseload as AEP is?

A. I would hate to generalize that much because, even the company that has a fairly substantial fleet of very effective lower-cost units can be in a position with maintenance or forced outages where their next incremental unit may be well above what the market can offer. So, in general, you're correct, but there may be circumstances where, again, the market provides more flexibility.

MS. BLACKFORD:

Thank you. That's all of my questions.

CHAIRMAN HUELSMANN:

Mr. Kurtz, it's noon. I assume you're going to be a few minutes.

MR. KURTZ:

A few minutes.

CHAIRMAN HUELSMANN:

Let's take a break, then, to about one-fifteen. We stand in recess until then.

OFF THE RECORD

CHAIRMAN HUELSMANN:

Okay. The record should reflect we're back in session. It's about one-twenty. Mr. Kurtz?

MR. KURTZ:

Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. KURTZ:

Q. Mr. Hinkel, you've had your position with PJM for less than a year; is that right?

A. My current position. I've been with PJM four and a half years.

Q. Okay. What was your prior position before the current position?

A. With PJM, I was a Manager of Capacity Adequacy Planning.
Q. What about before joining PJM?
A. I worked for about 27 years for what was then called Pennsylvania Power and Light, now PP&L Resources.
Q. Mr. Raff asked you some questions about the Kentucky statute that requires that native load be interrupted last in the event of a transmission problem. Do you remember some of those questions?
A. Yes, sir.
Q. And you indicated that network integration load and firm transmission are treated equally?
A. Yes, sir.
Q. Okay. Would an example of firm transmission, and you may have already answered this, be, for example, a generator south of Kentucky Power schedules firm transmission over Kentucky Power's wires to deliver to a load serving FT in New Jersey, for example?
A. They might use firm transmission service to do that. In my view, at least historically in PJM, that wouldn't be the normal way that would be done.
Q. It could happen, though; couldn't it?
A. Yes.
Q. Okay, and that same generator located south of Kentucky Power could purchase firm transmission to deliver

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generation to a load-serving entity anywhere in PJM, Pennsylvania, Maryland, etc.; is that right?

A. Once again, they could. It wouldn't be the normal way they would do it because they would, in essence, be paying a second time if they're ultimately delivering to load by taking firm transmission service.

Q. Would that mean that this Kentucky statute should not be much of a problem for PJM, then, since you're indicating that it's very unlikely to ever be in force?

A. Well, I think that's true, especially in the case of a situation where the problem, as outlined, is one of transmission facility problems, the typical situation where we encounter curtailment in PJM is more capacity related, the available energy to meet a peak load situation rather than a transmission system failure kind of related thing.

Q. As I understand your testimony, since this is a highly unlikely statute to ever come into play, in your opinion, does that mean that PJM had no objection to its existence?

A. I'm not qualified to offer an . . .

CHAIRMAN HUELSMANN:

Mr. Caldwell, do you want to object or . . .

MR. CALDWELL:

I think I'll object to that, Judge. That's on the books. It's the law.

Q. Okay. Since it's highly unlikely in your testimony to ever come into play, isn't it correct that PJM should have no problem complying with it?

A. I would think that would be the case.

Q. Okay.

A. We would probably want to review its meaning against our procedures and the like and ensure that we could follow that process.

Q. Okay. Now, if this Commission ever felt - assume AEP was approved to join PJM and this Commission felt that the statute was not complied with, would PJM agree that jurisdiction would be here in front of the Commission to determine whether or not the statute was complied with?

MR. LITTLE:

Your Honor, I object. He's asking for a legal conclusion.

MR. KURTZ:

I'll withdraw that question.

Q. You were talking about the stakeholder group. Let me start off this way. You've indicated that PJM can order that transmission be built where the PJM footprint is?

A. That's correct.

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Q. Okay. That would include Kentucky if AEP joins PJM?
A. That would be correct; yes.
Q. Okay. So the Board of Directors of PJM could order that a big, new transmission line be built somewhere anywhere in Kentucky that was deemed appropriate?
A. That could be an outcome of this regional transmission expansion planning process.
Q. Okay. Do you know whether a Certificate of Public Convenience and Necessity would be needed from this Commission to build such a line?
A. I don't know the specifics of Kentucky, but, in every jurisdiction that we do planning for, we fold the planning process into all the jurisdictional require- ments. We don't bypass jurisdictional requirements at all.
Q. Okay. Now, this stakeholder committee, how many stakeholders typically show up at one of these meetings?
A. It varies. The annual full review process for the regional transmission expansion planning is typically on the order of 150 people, and it usually runs a two- day session until we brief folks on all the plans and all the outcomes of the plans. Working sessions in a particular subregion for particular projects sometimes have a much smaller number of people. In some cases,

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in a plan that's very straightforward, everyone is familiar with the options, it might only be a handful of people participating in the discussion of that kind of plan.

Q. Is it one stakeholder one vote?

A. In reality, the stakeholder process, in terms of working groups and user groups and these kinds of committees, is more an advisory process. The ultimate authority under the agreements is vested either in the members where it is something that would require a vote of the Members Committee or with the Board of Managers.

Q. So, if the Kentucky Public Service Commission wanted to be one of these 150 stakeholders, they would be able to advise AEP on what to do, but there would be no vote where it would be binding on AEP or any PJM member?

A. That's correct.

Q. Okay. Would the Kentucky Public Service Commission's vote out of 150 stakeholders be the same as some grass roots organization somewhere who was concerned about just whatever interest that, you know, a five-member neighborhood association . . .

A. As a general matter in stakeholder sessions, the votes are more of a straw vote consensus building approach to things and typically, in a situation where there's not a unanimous or an overwhelming majority of the stakeholders who agree, we'll have more discussion. We'll see what the issues are, discuss it further, and see if we can reach some better consensus, or, in some cases, those stakeholder groups report out two positions. They report out a majority position and a minority opinion with both sides able to present to either the members or the Board of Managers, as appropriate, the positions on the issue.

Q. Now, where do these stakeholder meetings typically take place?

A. In generally, historically, we've held them somewhere in the Philadelphia region but more recently, as we've looked into the planning process, for example, in the Midwest, we've held meetings in Pittsburgh, some in Chicago. We would certainly hold meetings wherever it was appropriate based upon the particular issues being discussed.

Q. Now, if a state Attorney General's Office wanted to participate but they didn't have funding, is there a way for PJM to pay their way, for example?

A. I don't know that there's a direct way for PJM to pay their way to participate, but we also provide typically conference call capability so they could dial in, . . .

Q. Uh-huh.

A. . . . and more recently we've used an electronic facilitation mechanism that uses the Internet to allow us to present material so that participants who are on restricted travel budgets or travel limited can readily participate in the process.

Q. There are eight members of the PJM Board of Directors?

A. I'm not certain. I would have to look to see.

Q. However many members there are, has a state commission ever, as a condition to approving membership in PJM, required that they have a seat or a designee of theirs have a seat on the Board of Directors?

A. The Board is an independent body that's chartered, if you will, under the PJM Operating Agreement. So, really, to the best of my knowledge, there's been no discussion of revising that to include a member of a commission, for example.

Q. Well, a commission designee to be on the Board of Directors, is that something that PJM would consider as a condition to approving a membership?

A. It would have to be something that would be reviewed by the stakeholder process, because the process for nomination, selection, election of members of the Board of Managers is a process that's outlined under the PJM agreements. So changes to that would have to work through the agreement process.

Q. I was looking through Kentucky Power's Response to

Staff Data Request, 1st Set, 26. It's a summary of the differences between PJM and FERC's proposed SMD. I assume you're familiar with the document.

A. I've seen the document; yes.

Q. Okay. Pretty much it's the document's conclusion that the SMD and the PJM model are fairly consistent; isn't that right?

A. There are some notable differences, but, in general, they're very close; yes.

Q. So, if one was not a big fan of SMD, if a person thought that SMD was bad for Kentucky, would it make sense to approve the utility's membership in an organization that was fairly consistent with SMD, in your opinion?

A. I wouldn't compare PJM's structure with SMD given that SMD is not finalized. It was a proposal, and we do highlight a number of places where our model differs from the SMD model.

Q. The very first page of this comparison in bold print says, "Much of the Fundamental Design of SMD is Consistent With Current PJM Market." That's right out of the box opening bold heading.

A. That's correct.

Q. That's true; isn't it?

A. Yes.

Q. Okay. On Page 11 of this document, there's a reference to, at the top of the page, an MOU. I assume that means Memorandum of Understanding . . .
A. Yes.
Q. . . . between the PJM Board and the MACRUC member state public utility commissions. What does MACRUC stand for?
A. It's an acronym that designates the Mid-Atlantic Area Utility Regulatory Commissions. So it is the Commissions in the traditional footprint of PJM.
Q. Okay. Is there a Memorandum of Understanding between the PJM Board and the Southeastern public utility commissions?
A. No, not that I'm aware of.
Q. Well, why is there such an agreement with the Mid-Atlantic public service commissions but not with other commissions?
A. This was a memorandum that was developed by those commissions to govern their interaction with PJM since utilities that were regulated by them were members of PJM.
Q. Now, as a condition to approving Kentucky Power's participation in the PJM Pool, would the PJM Board be willing to enter into a Memorandum of Understanding with the Kentucky Public Service Commission, for

example, to dictate future interaction, so to speak.
A. I think we're certainly open to dialogue with any commission or representative group that would like to have a point of interaction, if you will, with PJM and its Board.
Q. So, for example, if this Commission were to approve the application at bar with the condition that the PJM Board agreed to A, B, C, D, E, that's something that PJM would consider doing?
A. We would certainly consider it; yes.
Q. Okay.
CHAIRMAN HUELSMANN:
Let me go on the record, and Mr. Little can correct me if I'm wrong. My understanding is that the original PJM was just strictly MACRUC states. The SEARUC states are about nine of us. We're a matter of the SEARUC, and, when AEP announced that they were going to join PJM, the people from PJM sent us a Memorandum of Understanding and told us they were going to rewrite that to eliminate the PJM only, . . .
VICE CHAIRMAN GILLIS:
MACRUC only.
CHAIRMAN HUELSMANN:
. . . excuse me, MACRUC only, and we, as a state,

have now joined MACRUC as a state. Mr. Little, is that . . .

MR. LITTLE:

Mr. Chairman, I believe that is correct. The current status of that is, in December of 2002, we had a discussion and a conference call with all the states. The result of that conference call was that the MACRUC, the traditional MACRUC, states were going to have discussions with Commissioner Hadley of Indiana as the spokesperson for the new states to discuss different paradigms for either a new MOU, three separate MOUs for MARC, MACRUC, and SEARUC, or any combination. They have not reported back yet.

CHAIRMAN HUELSMANN:

And MARC is the western states. Go ahead.

MR. KURTZ:

Thank you, Mr. Chairman.

CHAIRMAN HUELSMANN:

Does that clear that up for you?

MR. KURTZ:

Yes, I was not aware of any of the . . .

CHAIRMAN HUELSMANN:

I'm sorry, but that's . . .

MR. KURTZ:

Yeah.

Q. But, in any event, if this Commission were to approve Kentucky Power's participation in PJM transfer control of transmission, the PJM Board would consider any new or additional conditions that this Commission may attach?

A. Certainly.

Q. Okay. You had some discussion with Mr. Raff about participant funding versus rolled-in funding of transmission upgrades?

A. Uh-huh.

Q. Okay. Will you turn to Page 10 of this Data Response that we were just looking at, the second full paragraph? This discusses the transmission upgrade funding process. In just very general terms, I would like for you to flush it out a little bit for me, if you could.

VICE CHAIRMAN GILLIS:

Excuse me, Mr. Kurtz. Can you help me where you are?

MR. KURTZ:

I'm sorry.

VICE CHAIRMAN GILLIS:

I thought I was with you, but I - Page 10 of 18?

MR. KURTZ:

Page 11 of 18, Page 10 of the document.

VICE CHAIRMAN GILLIS:

Okay.

MR. KURTZ:

It starts off,"PJM conducts a fully integrated planning process." Sorry.

VICE CHAIRMAN GILLIS:

I thought you were on the 1st Set, No. 26.

MR. KURTZ:

Yes.

VICE CHAIRMAN GILLIS:

Page 11 of 18?

MR. KURTZ:

Yes, the second paragraph.

VICE CHAIRMAN GILLIS:

On the left or right?

MR. KURTZ:

Right.

VICE CHAIRMAN GILLIS:

Okay. I'm with you. Thanks.

MR. KURTZ:

Okay.

Q. This is the current PJM framework, a summary of that; is that right?

A. Uh-huh.
Q. Mr. Hinkel?
A. Yes.
Q. Okay. "PJM conducts a fully integrated planning process. The process establishes a base-line system that is compliant with reliability criteria and preserves all existing long-term firm rights regarding access to the transmission system." Okay. What is this baseline system, and would the existing long-term firm rights be, for example, a sale from a generator south of Kentucky Power? What I was putting forward to New Jersey, for example, would that be under the firm transmission rights that this would be referring to?
Q. The baseline study is the study I discussed earlier with Mr. Raff. It looks out three to five years at load growth, other system facility changes, and planned additions to the system. So it's forecasting load as it might grow or shift within the region, and it also does include any firm service, and another example of that may well be my understanding that AEP, to serve Kentucky Power, has firm resources outside the footprint that they bring into Kentucky Power to serve that load. That would be modeled as part of that baseline study.
Q. Okay. So we have the baseline. Then it says, "PJM ...

evaluates market driven needs, . . ." and that's a phrase that's used several other times. What are the market driven needs?
A. The example we talked about earlier was a new generator being connected to the system.
Q. What is market driven about that?
A. The generator has decided to locate within the PJM footprint and build a new unit there based upon what they perceive to be a viable market for that generation.
Q. Okay. So, if a merchant generator simply by virtue of the fact that it decides to build, that's deemed to be a market driven need?
A. Yes.
Q. Okay.
A. Yes.
Q. So the merchant generator decides to build a power plant, and then it goes on, ". . . such as generation interconnections, and identifies transmission system enhancements required to accommodate such market needs consistent with reliability criteria." So, if a merchant generator decides to locate in West Virginia - I think that was one of the examples Mr. Raff used - and then had transmission implications in Kentucky, that merchant generator is under this market driven

needs criteria; is that correct?
A. Uh-huh. Yes.
Q. Okay, and so the transmission ramifications of that are deemed to be part of the overall growth of the system, the market driven needs, and not assigned specifically to that merchant generator?
A. No. If the transmission need, the - an upgrade to the transmission system was required solely because of that generator connecting to the system, whether in Kentucky or West Virginia, in your example, the generator would be responsible for the costs incurred to upgrade the network to meet that requirement.
Q. Under all circumstances, even if the merchant generator was needed, as deemed by PJM, to meet load growth?
A. When we go back to the baseline study and we're looking at the baseline requirements around load growth, we're simply looking at that load growth. We're not looking at what new generation might be coming in to meet the load. We're just looking at the load growth per se.
Q. So it's your testimony that, if a merchant generator came in and caused transmission upgrade costs for whatever reasons under any circumstances, that that merchant generator would have to pay all of the transmission upgrade costs?
A. To the extent that those upgrade costs were solely

associated with that generator; yes.

Q. Okay. Now, what if there was a dispute between PJM and this Commission and the new Kentucky statute came into play? Who would be the final ruler, final decision maker, of that? Suppose, for example, PJM said, "Well, yes, there's a new thousand megawatt plant, but it did not solely cause transmission costs," and let's assume that the Kentucky Public Service Commission disagreed. What would happen?

A. It's a rather complex hypothetical, but the . . .

Q. Let me simplify it. A thousand megawatt merchant generator comes in. PJM says, "Well, yes, it caused $100 million of transmission upgrades, but it was not caused solely by the merchant. It was a function of other things," and this Commission disagreed with that assessment and thought that the entire $100 million was caused by the merchant. Who would win?

A. We've never encountered that situation. I can't come to a conclusion about how that would play out.

Q. Can you commit that PJM would agree to abide by what this Commission ruled on that? Can you make that commitment?

MR. CALDWELL:

Your Honor, I'm going to object to that question and . . .

CHAIRMAN HUELSMANN:

Well, I think Mr. Kurtz is entitled to ask the question. I'm not so sure this witness can make that commitment.

MR. CALDWELL:

Right.

CHAIRMAN HUELSMANN:

If that's what your answer is, we could get it as a Data Request.

MR. KURTZ:

I would just prefer an answer from the . . .

CHAIRMAN HUELSMANN:

Okay.

MR. KURTZ:

. . . PJM witness.

CHAIRMAN HUELSMANN:

If you know.

A. I can't directly answer that because it becomes a question of - my first response would be we would sort out that disagreement as part of the process and attempt to reach a consensus on what the cost causality was. That's how the process typically works. If that process breaks down, I can't say where it would go next at that point.

Q. You can't commit that you would abide by this

Commission's decision or PJM would not?

A. I'm not in a position to make that commitment.

Q. I asked Mr. Baker at the beginning of the hearing about the status of the Virginia legislation prohibiting Virginia utilities from joining PJM for a period of time. Do you recall that question?

A. Yes, sir.

Q. And I believe the Chairman indicated that that Virginia legislation was signed by the Governor yesterday. Were you aware of that?

A. I was not.

Q. Okay. What is PJM's position on the Virginia legislation?

MR. LITTLE:

Your Honor, I'll object. You announced into the record it was signed. Our position is irrelevant at this . . .

CHAIRMAN HUELSMANN:

And I didn't announce it. I said the trade journals reported yesterday that he signed it and made it an emergency.

MR. LITTLE:

I apologize

CHAIRMAN HUELSMANN:

Other than that, I have no knowledge. I think the easiest way to handle this, Mr. Hinkel, is, if you don't know, just say, "I don't know," but I think he's entitled to ask the question, but I don't think you ought to speculate, and there's nothing wrong with saying you don't know since you're with PJM and he's asking you questions about AEP.

MR. KURTZ:

No. I was asking him what's PJM's position on the Virginia legislation.

CHAIRMAN HUELSMANN:

If you know.

A. I don't know PJM's position on it.

Q. Okay. My understanding is that the Virginia legislation puts off a decision for approximately one year for that state.

A. There's actually three dates in the legislation. The first one is July 1 of this year by which time utilities that serve customers in Virginia are required to apply for membership in an RTO. My understanding is it prohibits them joining an RTO until July 1 of 2004, and the third date is January 1, 2005 by which date those utilities must be part of an RTO.

Q. Okay. Let's assume that that Virginia legislation is valid because it is the law. AEP could not join PJM before July 1, 2004; is that right?

A. That would be a choice AEP would have to make.

Q. Well, my question is, assuming that the legislation is valid, is there any rush for this Commission to decide? I mean, isn't the time frame July 1 of 2004?

A. I'm not sure what the question is.

Q. If AEP cannot effectively join PJM until it gets all its state commission approvals and at least one state cannot make such approval until July 1 of 2004, is there any rush here?

MR. LITTLE:

Your Honor, I'm going to object. The witness previously testified that he was not aware of what AEP's business decisions would be.

CHAIRMAN HUELSMANN:

I understand what you're saying. Once again, there's nothing wrong with saying, "I don't know," but don't speculate.

A. Yes, sir.

CHAIRMAN HUELSMANN:

Okay. If you know the answer.

A. I do not.

Q. Okay. You don't know if there's any rush, then, for this Commission to make a decision?

A. I don't.

Q. Okay. Do you know if AEP needs this Commission's

approval to join PJM?
A. I do not know.
Q. Okay, and you don't know what options AEP would have if this Commission turned down approval?
A. I do not.
Q. Okay, and, if this Commission approves Kentucky Power's membership in PJM and later it turns out to be a bad decision, do you know if PJM would let the Commission take back their decision?
A. The PJM agreements have provisions for the withdrawal of a party. They could certainly execute those provisions and withdraw from PJM if that's what you mean.
Q. Right. AEP could, . . .
A. Yes.
Q. . . . but the Commission, after it gives approval, would the Commission have any withdrawal rights?
A. I don't know.
Q. Now, AEP provided no cost-benefit analysis to show that joining PJM was a good idea. Did you hear that testimony earlier?
A. Yes.
Q. Is that typical, in your experience, of the utilities that are seeking state commission approval to join PJM?
A. To the best of my knowledge, it is.

Q. Okay. Most of the utilities you're aware of never tried to answer that question to their state regulators?
A. Not that I know of.
Q. Okay. I just want to ask you about the generation authority of PJM or their control over generation. PJM sets a reserve margin for its load serving entities; is that right?
A. That's correct; yes.
Q. Okay. Do you know what would happen if this Commission felt that the reserve margin set by PJM was too high or too low?
A. No.
Q. In other words, if we had a dispute, who would govern?
A. I don't know.
Q. Okay. Does PJM dictate what type of power plant that the utilities should build to meet that reserve margin need . . .
A. No.
Q. . . . or what type of resources?
A. No.
Q. Okay. PJM just sets the percentage and then it's up to the utility to choose how to comply?
A. Correct.
Q. Okay. Does PJM impose penalties if the utility does

not comply with its dictates on reserve margin?
A. Yes.
Q. Okay. What are the penalties?
A. There's two different sets of penalties and, under today's agreements, there are two different Reliability Assurance Agreements; one that covers the classic PJM footprint and a second one that covers PJM West. Each of those agreements have slightly different penalty structures, and there's very specific penalty amounts for a load server who fails to meet a capacity obligation in one form or another on a given day.
Q. Okay. What would it be for Kentucky Power, if it did not meet the PJM Board of Directors reserve margin requirements?
A. I don't know the absolute numbers of the deficiency charges off the top of my head.
Q. Do you have an order of magnitude, ball park, anything?
A. Well, in essence, the deficiency penalty is roughly tagged at the annual cost of a simple cycle combustion turbine and then divided up in the two agreements in different ways, either in time periods that are several months long or into daily increments depending upon the particular agreement and the business rules that it comes under, but the maximum deficiency cost over a year's time would be the equivalent carrying cost of a

simple cycle generator.

Q. Under what circumstances can the PJM dispatch generation owned by Kentucky Power?

A. If a generating unit is considered a PJM capacity resource, one of the resources that meets that capacity obligation, it's required to either self schedule or bid into the PJM markets and, in having bid into the PJM markets or self schedule, there's some level of control that PJM can exercise over it within those market business rules.

Q. Kentucky Power owns or leases two units, Big Sandy and Rockport. Would either or both of those units be PJM capacity resources?

A. They could be. That's a decision AEP will have to make in terms of meeting their obligations in the PJM market.

Q. Well, how does that work? What's the criteria for deciding whether they should be must run PJM units or not?

A. No. I think you're - I talked about a unit being a capacity resource. That's a decision that's made around the capacity value of the unit. Once that decision - and they can choose not to commit that unit as a capacity resource. If they commit it as a capacity resource, they can self schedule it or they can bid it into the market at their choice basically. That's the voluntary nature of the market.

Q. Okay, and under what circumstances can PJM order them to run it or sell into the market?

A. If they bid into the market, we would honor that bid. There could be cases where, for reliability purposes, for example, the constrained dispatch algorithm indicates that a unit is required to meet reliability needs. If it's a capacity resource, we can require it to run, if it's available.

Q. Once a utility is a member of PJM, PJM could change that dispatch must run criteria to be more or less stringent simply by a vote of its Board of Directors; couldn't it?

A. The process would require some level of stakeholder initiation. Someone would have to want to make changes. Those changes would have to go through the stakeholder process, ultimately through the FERC filing process, and that level of review before they would become active rules or changes to the marketplace.

Q. It's, yes, the Board of Directors could do it after it goes through the process?

A. The Board of Directors could initiate that sort of filing; yes.

Q. Filing at FERC?

A. Yes.
Q. Okay. So FERC would then control ultimately if there were any changes to the dispatch requirements currently in place? You have a stakeholder collaborative get together who would advise the Board. The Board would order its lawyers to do whatever the Board felt was right, and then PJM would make a filing at FERC, and then FERC would rule?
A. Yes.
Q. Okay. That would be true about how the Kentucky Power power plants are dispatched as well as the reserve margin rules and the ICAP rules; isn't that right?
A. That's correct.
Q. Okay. That would also be true about how much or how little Kentucky Power would sell its generation into the day-ahead and the hourly PJM markets? That process could be changed merely by filing at FERC?
A. The process could be changed that way; yes.
Q. Okay. So, theoretically, there could he a situation where FERC gave more and more control over Kentucky Power's generation through reserve margin, ICAP, dispatch, requirements to sell into hourly or day-ahead markets simply by filing at FERC; isn't that right?
A. Theoretically, that's true.
Q. Okay. Is there any limit to FERC's control over the

generation owned by Kentucky Power?
A. I don't know.
Q. If it was FERC's goal to equalize generation prices throughout a large region, PJM, for example, do you know of any limits on FERC's authority to do so after a utility . . .
MR. LITTLE:
Your Honor, he's asking for a legal conclusion. I object.
MR. KURTZ:
Okay. I'll withdraw that question.
Q. Do you think that this Commission will have more or less jurisdiction over Kentucky Power's generation to . . .
MR. LITTLE:
Your Honor, I object, again. He's asking for a legal opinion.
MR. KURTZ:
I would like to finish the question.
CHAIRMAN HUELSMANN:
Let him finish the question and see what the question is.
Q. Do you think that this Commission will have more or less jurisdiction over the generating resources currently used to serve ratepayers in Kentucky if

Kentucky Power joins PJM?

MR. LITTLE:

I renew my objection, Your Honor.

CHAIRMAN HUELSMANN:

If he knows the answer, let's - if you don't know just say, "I don't know."

A. I don't know.

MR. KURTZ:

Okay. That's it, Your Honor. Thank you.

CHAIRMAN HUELSMANN:

Mr. Overstreet or Mr. Duffy, do you all have any cross examination? I hate to interrupt you, but I don't think you do, but I didn't . . .

MR. OVERSTREET:

I'm sorry.

CHAIRMAN HUELSMANN:

It's up to you.

MR. OVERSTREET:

No, Your Honor.

CHAIRMAN HUELSMANN:

Okay. Commissioner Gillis?

EXAMINATION

BY VICE CHAIRMAN GILLIS:

Q. Mr. Hinkel, I just wanted to follow up a bit on Mr. Kurtz' questions as far as transmission upgrades and the need, and so forth. In the last five years, can you tell me how many transmission upgrades have been made either for interconnection or for the systemwide?

A. I believe there were a few numbers in my testimony, Commissioner.

CHAIRMAN HUELSMANN:

Page 13, Line 18, has got the dollar amount. It doesn't have the miles.

Q. I'm just interested in the number of different . . .

A. I don't know the absolute number of different things, but they range from very simple and straightforward, a replacement of a circuit breaker or a piece of substation equipment to new transformers, line reconductoring, and a few new lines. I don't have at my grasp the absolute number of projects or specific instances of what was done.

Q. As far as the number of lines, would you have any idea?

A. There are only a couple of new lines built in that whole process. Most of the work was substation type work or, in a few cases, the reconductoring of several lines in existing footprints.

Q. Okay. Of the lines that were built, a couple of lines, were they for just interconnection or for systemwide service?

A. They were typically the kinds of upgrades where new generation wanted to site in a particular area and, to provide deliverability of that generation to the load, upgrades to the system were required and a line reconductoring, for example, was the best economic solution to do that.

Q. Okay.

CHAIRMAN HUELSMANN:

Let me interrupt a second. Could you produce a list of those miles . . .

A. Certainly.

CHAIRMAN HUELSMANN:

. . . as a Data Request and what state they were in . . .

A. Certainly.

CHAIRMAN HUELSMANN:

. . . from 1999? Because that's an area that I have interest in also, and I assume you . . .

VICE CHAIRMAN GILLIS:

And I'm going to add to that here after I get through.

CHAIRMAN HUELSMANN:

Oh, excuse me. I'm sorry. Go ahead.

Q. Of the two or three that were built, how many of those were paid for by the generator? Well, we'll stop there. How many were paid by the generator?

A. At least, some portion of them was paid for by generators. They may well have been in this area where the reenforcement was done, in part, because of a new generation request and, in part, because of normal load growth. So there might have been some cost sharing of those things, but we can look at how that allocation was done as part of the Data Request you've put on the table.
Q. Okay. That was, additionally, a second part of what I was wanting and I'm interested in how many are also fully paid by rolled-in pricing or socialized pricing or however you care to characterize the rolling in of the prices. Were any for systemwide upgrade and, in turn, the pricing totally rolled into the rates?
A. Indeed, the number that appears here is $200 million of baseline upgrades. They would be costs that would be rolled into the normal transmission revenue requirements of the utilities. The remaining costs were upgrades that were paid for directly by participant funding by the generator who is locating on the system.
Q. Okay.
A. We can break that down on a project basis.
Q. That was what I was wanting broken down, how many by generator, how many hybrids, and how many systemwide, and, following up on Mr. Kurtz' question, how is the

process determined as far as which is for reliability and which is for the cost-causer or the responsibility of each? How is that determined?

A. Analytical studies have been done by our system planners who are looking at these current data models of the systems and, in the forecasted future models, taking into account load growth and other changes that the transmission owner is doing, and then layering on top of that the generation interconnection request to find out what has changed as you go from one to the other, and there's a whole methodology they have for developing that cost causality and attributing that cost to either the baseline changes - we needed a new transformer because load was growing in the area - versus a change because we've added a new generator and the generator should pay for it.

Q. I want to follow up one question on there's growth in the area. Do you mean wholesale growth that may be transferring across the system or growth in Kentucky Power's area for NLCs?

A. Principally growth because of the load within the region and just an example that I am familiar with and it's a straightforward one because it's the Delmarva Peninsula. We had a case where the Peninsula load was growing, and yet there was a generator locating on the southern end of the Peninsula which was a good thing because, in aggregate, the amount of reenforcement required by the transmission owner was reduced because the generation was being located there. So they balanced that cost between the two of them.

Q. I think that sort of wraps up my questions, but those pieces if you could include in the . . .

A. Yes, sir.

CHAIRMAN HUELSMANN:

I have a few questions.

EXAMINATION

BY CHAIRMAN HUELSMANN:

Q. As part of the packet that I have, I have a document styled "PJM RTO Reliability Plan Draft Version, October 22, 2002"? Are you familiar with that document?

A. Yes, sir.

Q. Did that ever reach final document form?

A. The document is still a work in progress because it is intended to cover ultimately the place where we have markets in place across the new footprint. It reached a level late last year, which is what you saw in this draft, where it went before the NERC formal approval process for approval for the first phase of the transmission, moving these companies into PJM from a transmission service perspective; not the full market implementation. So it was approved at that level by the NERC community late last year but is still being revised to reflect additional requirements as we move toward the market implementation.

Q. We're new at PJM, so bear with me a little bit. In your testimony on Page 7, you mention "Board of Managers"?

A. Yes.

Q. Is that the same thing as the independent board?

A. That's our independent board; yes, sir.

Q. Okay, and you state that they meet on a regular basis with state commissions. How regular do they meet?

A. They have a formal scheduled meeting annually, and I'll say informally by phone call or other meetings as required.

Q. Are there Minutes of any of these meetings available?

A. Not that I'm aware of.

Q. On Page 8 of your testimony, you note that the spot market accounted for 18 percent of the energy in 2000, 21 percent in '01, and 38 percent in '02. Why did it so dramatically go up in '02?

A. I think that the detail of that is more appropriately answered by Mr. Ott, but I think there has been some shifts in both the divestiture of generation. We have new participants who aren't the traditional incumbent

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vertically integrated utilities. The transparency of the market, the stability of the market, moves people a little more towards the spot market.

Q. On Page 10, you mention LMP is an effective congestion management tool, and it provides for construction and new generation. How much has LMP caused new generation in the last five years?

A. It's difficult to attach how much new generation is being built just to that one factor. LMP is one of the many factors causing generators to want to build in the PJM footprint. So it would be hard to say, "The LMP differences created this many projects." We do know that the initial projects that were built were being built in the areas with the highest congestion. So the LMP price signal caused generators in a first-round consideration to look at places where the most congestion existed, but to try to isolate that one causal factor to this much generation would be pretty difficult, sir.

Q. Okay. On Page 13 where Commissioner Gillis was before, it takes a long time to get a plant on line. How many plants are under construction right now on the PJM footprint, or do you have that as a working document someplace?

A. One of the attachments to my testimony - it was an attachment under Tab D in my material - had two pages that showed the queued capacity. That's an indication of the number of new generation requests. Across the queues are multimonth blocks of time that we have people applying. So, if you look at where we're at, and this was as of early this year information, approximately a little less than 8,000 megawatts of new generation in service with another 8,000 planned in 2003. So each year we have that moving target of how many units are being planned, and they're all at various stages of preliminary analysis, detailed analysis, or construction in that process.

Q. Has PJM ever ordered generation to be built or transmission lines to be built?

A. We haven't directly ordered generation to be built. The capacity requirements that are part of our Reliability Assurance Agreement and the price signals of LMP generally provide the motivation for new generation to locate in PJM.

CHAIRMAN HUELSMANN:

Okay. That's all I have. Any redirect, Mr. Little?

MR. LITTLE:

Your Honor, may we go off the record or off the air for just a brief moment?

CHAIRMAN HUELSMANN:

Let's go off the record.

OFF THE RECORD

CHAIRMAN HUELSMANN:

Okay. We're back in session. It's a little after ten after two. Mr. Little?

MR. LITTLE:

Your Honor, we have no redirect. At this time, I would like to move for the admission of PJM Statement 1 into the record.

CHAIRMAN HUELSMANN:

PJM's . . .

MR. LITTLE:

Mr. Hinkel's testimony.

CHAIRMAN HUELSMANN:

Oh, his testimony comes in.

MR. LITTLE:

Okay.

CHAIRMAN HUELSMANN:

It's filed of record and comes in. Excuse me. Mr. Raff, any recross?

MR. RAFF:

Yes, I have a few more questions, Your Honor.

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RECROSS EXAMINATION

BY MR. RAFF:

Q. Mr. Hinkel, are you aware of articles that have been written in trade presses and statements made by people in the electric utility industry, including those of FERC Commissioners, that there's a real crisis in the industry today because of a significant underinvestment in transmission facilities that has been occurring over the last, I think, two decades?

A. I have seen some of those articles in the general trade press; yes.

Q. Do you believe there's any truth to those kind of statements?

A. I think it's very situational and, as a global statement, it may or may not be correct in a given space.

Q. Is there, to your knowledge, any problems within the PJM footprint as a result of underinvestment in transmission facilities, or has there been any under-investment in the PJM footprint?

A. I'm not sure I could quantify underinvestment or over-investment. I can state that the PJM footprint meets the applicable regional reliability requirements under NERC guidelines, and, from that perspective, there's adequate transmission facilities to serve the load reliably.

Q. So, as far as you know, there has been no reluctance by any of the PJM members to build transmission facilities that were needed to serve load and maintain reliability?

A. To the extent that those requirements have been found in our planning over the past several years, in particular, that work has been ongoing.

Q. Okay. In your testimony at Page 13, towards the bottom of the page, you've got the statement there about $726 million of transmission upgrades and, prior in the sentence, you said that this is since 1999. That refers to, I guess, the 7,000 megawatts of new generation. Does that also apply to this $726 million of transmission upgrades?

A. Yes, sir. The $726 million of transmission system upgrades, $200 million of which are those baseline reliability type upgrades, the remainder of $526 million are in support of that new generation addition that has occurred over those planning cycles.

Q. And the term "since 1999," does that mean, then, starting January 1 of 2000 through the end of 2002? Is that what we're talking about here?

A. It's really a marker for the point in time where we started the regional transmission expansion planning process. So that process began partway through 1999 and has cycled through on an annual basis since then.

Q. So we're talking three years or more?

A. Three operating years of planning; yes.

Q. Okay, and then $200 million of the transmission expansion was for these baseline upgrades and then I guess you would subtract out that $200 million, and say $526 million was to add new generation or new generators?

A. That would represent the participant funding for new generation; yes.

A. Okay. So that was paid by the generators; not the existing transmission owners?

A. That's correct.

Q. All right. Of the $200 million in these baseline upgrades, that's over three years?

A. Roughly, yes.

Q. So that's about $67 million a year, and it appears that you have, is it, ten or eleven members of PJM?

A. Yes, sir.

Q. That comes out to, just on an average basis, less than $7 million per year per utility. Is that not an awfully small amount for transmission upgrades?

A. Well, remember, sir, the $200 million are just those upgrades that were required to meet the baseline requirements, the reliability requirements, related to load growth.

Q. Right.

A. The additional $526 million clearly represent transmission system reenforcements and upgrade to support that new generation interconnection on the system so the cost of that borne by the generators still represents improvements in the capability of the overall transmission network.

Q. Mr. Kurtz was asking you some questions about the schedule that AEP/Kentucky Power had provided in Response to the 1st Data Request, Item No. 26, Page 11 of 18, the comparison between the existing PJM frame-work and the standard market design, and the last item that I think you were discussing had to do with, under the PJM column, the sentence that says, "Cost responsibility for transmission system upgrades is assigned on a cost causation basis." Do you see that?

A. Yes, sir.

Q. Could you file copies of whatever is in the PJM tariffs that set out this policy regarding cost causation and who pays?

A. Certainly. It goes to the Data Request we got earlier from the Commission. We'll wrap that into a package that demonstrates the process, its fundamentals in the agreements, and then the specific statistics around additions in the three year period.

Q. That would be great. I think Mr. Kurtz was also asking you something about the potential delay in AEP's membership in PJM as a result of the new statute in Virginia. Was it your understanding that AEP's original intent was to try to become a member of PJM, I think, by the end of this month?

A. We had originally worked with them on a target implementation date of May 1; yes.

Q. Okay. Assuming that there is a delay of 14 months, till mid 2004, from PJM's perspective, what problems, if any, does that cause PJM?

A. Operationally, if you want to explore operational difficulties, it really doesn't change the way we're operating today. We were in the process of building systems to encompass the new additions, but it doesn't change how we operate today. It just doesn't expand the marketplace, in essence, until they do join.

Q. All right, and, assuming AEP does join mid 2004, other than that 14 month delay, I mean, does that cause any other integration processes to be further delayed beyond a 14 month period?

A. Let me first clarify that, even though the Virginia requirement has a date of July 1, 2004, as a matter of policy, we would not implement a major market transition, such as bringing AEP into the PJM market at that time. We've got a standing policy that basically says we will not make significant adjustments to our overall systems through the summer months from a reliability perspective. So our reality would be that that integration would occur with that delay September 1, more likely October 1. So it would be a little longer than 14 months.

Q. Okay.

A. I'm not sure what the rest of your question was, sir.

Q. Well, I was trying to figure out, once the day of joining comes, I assume there is still some period where the systems have to be integrated, and there is a period of time before everything is operational, and they would be considered to be in the same category as your existing PJM members.

A. Okay. The reality of our implementation planning would have that occur on that date. Our system integration and changes to our systems to model AEP, for example, to integrate AEP and other load servers in their footprint into the PJM markets and models and the like, would all precede that date so that, on that date, we could actually do the market transition, have them fully integrated into the market at that time.

Q. Okay. So then there would be no further delay beyond whatever period of delay was created by the Virginia statute and the PJM policy of not integrating during the summer months?
A. There would be no further delay for AEP being integrated into our market; that's correct.
Q. I think the Attorney General's Office had asked you a question about the fact that there is a statute in Kentucky that requires regulated utilities to get Certificates of Convenience and Necessity prior to constructing major transmission facilities and the extent to which that requirement would be followed by PJM, and I believe you indicated, you know, that your planning process was done in recognition of and in conjunction with whatever state construction requirements existed. Is that accurate?
A. Indeed, the responsibility to build goes back to the transmission owner, and they would follow all the processes they're following today.
Q. Have there been situations in the past where PJM has directed one of its members to construct new transmission facilities and that has then led that member to make a filing before its state commission for approval of the construction?
A. I'm not personally aware of any, but there have been

new facilities built and indeed line reconductorings that may well have come under those requirements.

Q. Okay. So then you wouldn't know whether PJM participated in those state proceedings regarding the need for the new facilities?

A. I know that, as a part of the regional transmission expansion planning process, in some of the states personnel or staff from the siting board or commission staff participate in the process specifically to be aware of planned additions to the systems and ensure that they're cognizant of what's going on from PJM's planning process along the lines of what their other requirements are.

Q. But you, then, personally have not been designated to participate as part of a state commission proceeding in which one of the PJM members was requesting authorization to construct transmission facilities that had been part of the PJM planning?

A. I am not aware that we have, sir.

Q. All right. I believe that the Attorney General's Office had started out by asking you a question about whether giving a preference to native load customers would constitute any kind of discrimination on the transmission system, and I believe your response was that serving native load had the highest priority and

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would not be considered to be discriminatory.

A. Yes, sir. I think the question was in the context of the mandate, if you will, PJM's charter statements, that we ensure that there isn't undue discrimination, and my statement was that serving native load first is a part of the FERC doctrine, the state doctrine, and it is our priority.

Q. I'm trying to reconcile that with what you had previously stated about, while, for example, Kentucky Power serves its native load with network integration service, that there are other entities out there who purchase firm power services and that anyone who purchases firm power service is on an equal priority footing with native load customers. So it seems then that native load doesn't have the highest priority.

A. Well, and perhaps, if I add a little more of how that comes about, . . .

Q. Sure.

A. . . . it will help address that. In the process of granting that firm transmission service, there is a body of analytical work done to ensure that the available capability of the transmission system can meet both the network service load requirement and the firm service load requirement, because those two, from our tariff's perspective, are on par in terms of priority, but we wouldn't grant firm service if we couldn't guarantee that those two could coexist.

Q. So they can coexist, theoretically, under your planning process, but, if, in actuality, there is an unexpected event on the transmission system that causes there to be a need for some interruption of service, the service is interrupted on a pro rata basis?

A. That's correct.

MR. RAFF:

All right. Thank you. Nothing further, Your Honor.

CHAIRMAN HUELSMANN:

Ms. Blackford?

MS. BLACKFORD:

Nothing.

CHAIRMAN HUELSMANN:

Mr. Kurtz?

MR. KURTZ:

No more.

CHAIRMAN HUELSMANN:

Mr. Overstreet?

MR. OVERSTREET:

No, Your Honor.

CHAIRMAN HUELSMANN:

Any re-redirect?

MR. LITTLE:

No, re-redirect, Your Honor.

CHAIRMAN HUELSMANN:

May this witness be excused? Thank you. Do you want to call your next witness?

MR. LITTLE:

Your Honor, PJM calls Andrew L. Ott as its second witness.

WITNESS SWORN

CHAIRMAN HUELSMANN:

Thank you.

The witness, ANDREW L. OTT, after having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. LITTLE:

Q. Would you please state your name and address for the record?
A. Andrew L. Ott, 955 Jefferson Avenue, Valley Forge, Norristown, Pa.
Q. Do you have before you PJM Statement No. 2?
A. Yes.
Q. Was this testimony prepared by you or under your direction?
A. Yes.
Q. Do you have any corrections or additions to offer at

this time?

A. Yes, I do. There were two typographical errors; one in my testimony and the other in the attachment. The first is on Page 8, Line 17. The first word there says, "cots." It should be "cost." The second correction is in the attachment to my testimony, Attachment A. On Page 8 in the table under "Load Payments" under the first column for "Combined RTO Total," there's an extra "4" on the end of that number. That "4" should be deleted. That should come out to be $15,401,000.

Q. Mr. Ott, if I were to ask you the questions contained in your testimony today, would your answers be the same?

A. Yes.

MR. LITTLE:

Mr. Ott is now available for cross examination.

CHAIRMAN HUELSMANN:

Mr. Raff?

MR. RAFF:

Thank you, Your Honor.

CROSS EXAMINATION

BY MR. RAFF:

Q. Good afternoon, Mr. Ott.

A. Good afternoon.

Q. Let's turn to Page 3 of your testimony, please, Lines 14 and 15.
A. Yes.
Q. Are you saying here that, if Kentucky Power joins PJM, that Kentucky Power will experience a decrease in its cost of power supply?
A. No, I don't think it's saying that. It's saying, in a wholesale market, the lowest cost of power that's available at that time can be purchased. That's what the spot market does. Obviously, Kentucky Power has facilities today that they may use by either self scheduling, as we have heard in previous testimony, or by purchasing directly from the spot market, and, again, that's a voluntary decision.
Q. Okay. So have you done any analysis that concludes that Kentucky Power can buy power cheaper if it was a member of PJM than it can either produce it or buy it from the AEP Pool currently?
A. Kentucky Power in isolation, no. The study I had performed was an integrated AEP System.
Q. Okay. Do you have the Responses that Kentucky Power filed to the Commission's 1st Data Request?
A. No.
Q. All right. If someone could give you a copy, it would be appreciated. If you could, take a look at Item 11,

please. We asked Kentucky Power to tell us for each month in the last three calendar years to show the cost to purchase power from non-associated companies, and then we asked Kentucky Power to tell us, if they had been a member of PJM, what those prices would have been. They said they were unable to calculate that. Would it be accurate that PJM also would be unable to calculate what prices would have been if Kentucky Power had been a member of PJM during this period of time?

A. You mean calculate them in the past, to try to recreate the past? Is that what you're asking?

Q. Yes.

A. Yeah, probably, to try to recreate the conditions that existed in the past would be very difficult. I couldn't think of a way I would do it.

Q. Okay, and then, in Response to Item No. 10, we asked Kentucky Power to provide a schedule showing, for the last three years by months, the revenues received from sales to non-associated companies, and they provided those revenues, and then we asked, if Kentucky Power had been a member of PJM, to provide us with a schedule showing what the revenues they would have received from these sales as a result of PJM membership, and they also said they were unable to calculate that.

A. Right.

Q. Would that also be something that would be most difficult, if not impossible, for PJM to calculate?
A. Yeah. Well, yeah, if I could put it in perspective, today, under PJM, I have data for PJM membership. I have settlements data. I have data on offer curves for generators. So, if I had that kind of widespread data that covered my entire footprint like I do for PJM members today, you know, those kind of analyses you could possibly start to recreate. You know, it would take a lot of work, but you could recreate such a - but the problem is you have missing data because there are other entities that are, you know, not part of that company or part of the market. So you have missing information, if you will. That's what would make it difficult.
Q. All right. At Page 7 of your testimony, Lines 7 through 9, you discuss your market analysis.
A. Right.
Q. Does the spot market energy price in Kentucky go up or down as a result of Kentucky Power joining PJM?
A. In this analysis, I didn't look specifically at the Kentucky Power price. If you look at the total AEP zonal price, which includes - you know, part of that would include Kentucky. Because the load payments reduce, the load price would be going down in aggregate

across the year. Now, obviously, during some hours, it would go up; some hours it would go down, but, in aggregate across the year, in my testimony it indicates a reduction of $61 million in load payments. That's consistent or would indicate that the total load price - and it's across the AEP entire load zone. I did not - because AEP is an integrated system, we really didn't look at the individual pieces of that.

Q. All right. At Page 8 of your testimony, Lines 6 through 9, . . .

A. All right.

Q. . . . you reference total savings from a combined RTO energy market . . .

A. Right.

Q. . . . in comparison to the current paradigm where each utility dispatches its own system and enters bilateral contracts. Are you saying here that your market analysis is based on the assumption that Kentucky Power sells all its generation on the spot energy market and serves its native load by purchasing energy on the spot market?

A. The number, the $932 million total, would assume 100 percent spot. The number for generation production costs would not assume spot. It would assume bilateral activity, which is more or less the generation directly

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assigned to serve the load. So, if you look in this analysis, we actually present numbers, the numbers in different - quantify them in different ways, if you will. The load payments and generator revenue numbers are really a spot market type number where you have the clearing price at each location, and you would assume in that case that the transaction is done at that clearing price. If you're looking at the generation production cost numbers that are reported or the numbers having to do with purchased power, those would be assuming a bilateral activity.

Q. Okay. I'm thoroughly confused. Let me pass out here - we've blown up, just for convenience purposes, copies of your schedule at I think it's Page 8 of your attachment, the . . .

A. Yes. Thank you.

MR. RAFF:

Okay. I'd like to have this identified as Staff Cross Exhibit No. 4, please.

PSC EXHIBIT 4

(MARKED FOR IDENTIFICATION)

Q. And this is the page to which you made the correction, which . . .

A. Right.

Q. . . . don't know if you picked up on this, but,

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anyway, maybe you could kind of walk us through this . . .

A. Sure.

Q. . . . schedule, and, you know, kind of line by line, column by column, to try to tell me what this is and what it means.

A. Okay. If you look at the first line, which is load payments - would it be all right if I just concentrated on . . .

Q. Sure.

A. . . . the AEP change at this point?

Q. Sure.

A. Okay. If you look at the load payment column, what essentially this is, is it's a comparison. The minus $61 million essentially means a reduction of $61 million between two simulations. The first simulation would have been a simulation that had, you know, individual security constrained economic dispatches, meaning a generation in an area, like AEP, would be designated to serve the load in the area of AEP, and you would use a least-cost security constrained dispatch which essentially means you would pick the cheapest. Every hour you would pick the least expensive generation to meet the load based on the production cost. Okay . . .

Q. Meaning what - the existing system, what they do now?
A. Right. The existing, right. Essentially, it's a model of the way they, you know, would do it today, "they," meaning AEP would meet their load today. Obviously, you know, they would be prudent and pick the cheapest generators to serve the load if they were available, of course. So this analysis would essentially try to replicate today's system and included AEP, Dominion, you know, the current PJM as separate entities. Now, and then you would run a larger model that had those same entities in the model but operating under one large security constrained economic dispatch. Now, one of the by-products of a security constrained economic dispatch is something called a locational price, locational marginal price. That by-product, you know, has existed for years. There were - you know, it's a natural by-product of the calculation. You really don't have to do something special beyond that economic dispatch you do to run the system. That essentially quantifies the cost to serve load, you know, the next increment of load or the cost at the margin to serve load, which is different than average production cost. So the cost at the margin would mean the cost to serve the next increment of load, meaning, if I loaded up on the stack of generation, if I had to go through the $12

generators, the $15, up to the - and I'm up at $22, and I've loaded that the last one, then the marginal price in that area or perhaps all over a system, if it were unconstrained, will be $22, where, if you quantify the average production cost, it would be lower than that. So this number of load payments compares that hourly marginal price at the load, in this case the AEP zonal load, between those two cases on an hour-by-hour basis. It takes the price times the megawatts. The difference between that product summed across a whole year is $61 million. Now, of course, when you make that comparison, the first observation that you would make is that today there is no such thing as a locational marginal price in AEP. All right. So what this number quantifies is today in PJM we have a locational marginal price. Okay. It really reflects the cost to serve the next incremental load. So, if every bilateral contract in AEP today were struck at, you know, margin, if you will, which is probably not true, the $61 million would be something you could use. So that's why we present other numbers, because, in some areas, the locational marginal price or the marginal price would have relevance. I think it's a good indicator. Whether the current area has a market or not, it's a good indication of what's going on, like you had asked the question before, "Does the load price go down?" and this is an indicator of that, but, if you look at the next number, to the generation production cost, that's the actual, what I'll call, traditional production cost number, which is the true average production cost to serve the load added up for each hour, and, in my attachment, it actually explains what the components of all those costs are, start-up costs, you know, hourly, no-loads, etc. So, if you look at that, the cost of production increased by $340 million and essentially a lot of that is because of increased sales. If you look at the purchased power cost of $420 million, essentially what that shows is a sale again. So, if you take the $420 million minus the $340 million, which is really looking at the bilateral contract type look at this where you're saying, "I'm going to compare the bilateral contracts in the individual dispatch cases to the combined," if you take the difference between those two, that's $80 million. That's essentially the difference between the power sales at the contract price and the cost of production. So that would look like, if you will, a savings. That's where the $80 million comes from that's in my testimony elsewhere. So I add the $61 million to $80 million. The $61 million was based on spot activity. The $80 million was based on bilateral activity. Am I getting too detailed or is this . . .

Q. I have no idea what you're saying, but that's okay. Continue.

A. Okay. So the point is, if you're trying to quantify the difference, you're saying, "I'm going from an area that does not have a market today to having a market. I can't compare, based on marginal price alone, because today there is no marginal price." If I compare it totally on production cost only, then, once you get into the market, there's benefits to be gained beyond just the savings in production cost. There's also the efficiencies to be gained inside the market itself. So the reason we report four numbers isn't really to try to confuse as much as it is to try to give additional information. So, when you take the difference in net purchased power cost and the generation production cost and that's an $80 million difference, that's another way to quantify or to measure the potential benefit, if you will, of forming a larger market and the benefit in terms of, you know, you have increased efficiencies, if you will, of dispatch, and then the generator revenue number is, again, another spot market number, where, if every generator were paid its locational marginal price every hour, you would see a number of $570 million.

Again, that has less relevance here because, again, the market is not 100 percent spot. Again, it's just provided to give an indication of, you know, what's happening in these simulations.

Q. All right.

VICE CHAIRMAN GILLIS:

So, if I take all four of those numbers and add them up, I'll have what? You would think you would have a chart with four numbers in it that you would be able to add, subtract, and come to a bottom line. Can I do that?

A. Now, the bottom line . . .

VICE CHAIRMAN GILLIS:

Are you saying that none of these are linked?

A. No. The two that are linked that you would want to subtract are the net purchased power cost and generation production cost. If you take the difference between those two numbers, that's saying that, if they were selling the energy out, the net, you know, savings or revenue on that would be $80 million, if you're looking at a bilateral type arrangement. If you wanted to look at the load payment from a spot market perspective, you could look at this $61 million and that's another quantification of potential savings. These are really ways to try to measure in dollars what the efficiencies that are gained by increasing the size of the economic dispatch. So, if somebody said, how much - when I tell you the market is more efficient as it gets larger, you ask me, "Can you quantify the efficiency?" and that's what the $80 million or the $61 million would do. It's really a quantification of the dollar value. That's . . .

Q. But is the $61 million reduction in load payments based on the assumption that all power is sold into the spot market and there's no bilateral contracts?

A. Right. The $61 million is based on the no bilateral contract. The $80 million is based on pure bilateral contract.

Q. All right, but this is for AEP as a whole; is that correct?

A. Integrated, right.

Q. The generation that Kentucky Power owns and has under contract is some of the lowest cost on the AEP System. Have you seen those numbers from Platts?

A. I'm sure they're in this model. I haven't specifically looked at those numbers.

Q. I think it was referred to earlier. Let me just - well, if you have that - oh, I'm sorry. It's a Response to a Data Request, but it was updated since that one was filed. That's a copy and the top half of the page . . .

A. Uh-huh.

Q. . . . shows the production cost figures for the AEP Companies, . . .

A. Right.

Q. . . . and Kentucky Power's is just under $12.50 a megawatt-hour?

A. Right.

MR. LITTLE:

Your Honor, can Mr. Raff identify for the record exactly what Mr. Ott has?

MR. RAFF:

It has, and I'm reading from the upper corner of it, "KPSC Case No. 2002-00475, Supplemental Data Requests, Order Dated February 28, 2003, Item No. 10a, Page 1 of 1, Updated and Filed March 12, 2003."

MR. LITTLE:

Thank you.

Q. The generation that Kentucky Power owns and has under contract is some of the lowest on the AEP System. Would you accept that, subject to check?

A. Yes.

Q. Would that indicate to you or would you accept, subject to check, that that generation is very high in the queue of the economic dispatch and, if those units are operational, that they are run 24 hours a day, seven days a week?

A. Yes. The costs that you're showing here look like a baseload unit, which would have that characteristic, absolutely.

Q. Okay. So would that indicate that, in your schedule, to the extent that there was any generation production cost changes, that there would not be a change to the cost experienced by Kentucky Power?

A. Yes. Without actually verifying the number, I would guess that, if you had a generator that were extremely cheap, if you will, or inexpensive, that, in the analysis, that would be running flat out during all the times it was available in both of the analyses, meaning in the individual run and in the combined run. In fact, certain nuclear plants I had actually looked at, not in this area, but had had that characteristic where they ran and the only time they were out was during a forced outage.

Q. Sure, and would it also be reasonable that, with the way the costs are allocated under the AEP Inter-connection Agreement with each member being assigned the cost of their own units to the extent of their load, that most, if not all, of the owned and under

contract generation for Kentucky Power will still be
used to meet its load such that any changes in
purchased power would be a result of other members in
the AEP pool rather than Kentucky Power?

A. Yeah. I mean, it would make sense, if you had a
generator that was bilaterally assigned, you know,
either contractually or otherwise, to a specific load,
then, in the billing, you know, and whether it's a
simulated billing here or the actual PJM billing, you
know, any system sales from that would probably go off
of another generator, again, to the extent that that
inexpensive generation is available. Obviously, if
it's not available, then it - but, in our case, for
this example, it would have been not available in both
cases.

Q. You just lost me there. Would have been not available?

A. Let me clarify. All of these kinds of simulations have
a certain assumption for forced outages, a certain
assumption for maintenance outages. Those were the
same in both the individual run and the combined run.

Q. Okay. I understand now. The generation that you
considered as part of AEP, was that limited to the
generation that is owned by the five utility members,
or did that also include the generation that AEP owns
as exempt wholesale generators?

A. It would include all generation owned by AEP. I wouldn't have had the information to distinguish. So it probably would have been anything that's considered owned by AEP, the corporation.
Q. All right. So then, to the extent that there may be 4,000 to 5,000 megawatts of generation that is not part of the AEP Pool because it's part of the unregulated, to the extent that there will be profits from those sales, those won't go back to the AEP Pool members; will they?
A. I don't know how the allocation - do you mean in AEP's accounting? I wouldn't know how that works.
Q. Okay. Well, you understand there is a Pool Agreement amongst five regulated utilities for, you know, its own Power Pool, and, to the extent that there are efficiencies by selling power within the Pool members, they do so, and, to the extent that there is excess generation that can be sold off system, they do so. The profits are then allocated amongst the Pool members . . .
A. Okay.
Q. . . . but, to the extent that there may be 4,000 to 5,000 additional megawatts of capacity owned by AEP as EWGs, . . .
A. Uh-huh.

Q. . . . that capacity is not part of the Pool.
A. Okay.
Q. So none of the benefits or detriments, whatever, have any implication for the Pool members, including Kentucky Power.
A. Okay.
MR. LITTLE:
Your Honor, for clarification, Mr. Ott was saying, "Okay," but was Mr. Raff testifying or asking a question?
CHAIRMAN HUELSMANN:
I kind of agree. Was that a question, Mr. Raff?
MR. RAFF:
I think I was asking whether he agreed, and I thought he said, "Okay."
CHAIRMAN HUELSMANN:
Did you agree with what he said?
A. Well, I mean, I don't have knowledge of AEP's accounting systems, meaning their contractual pooling relationship. I was just saying, "Okay." So I wasn't testifying that I know what AEP does internally in their accounting.
CHAIRMAN HUELSMANN:
And, once again, if you don't know, there's nothing wrong with saying, "I don't know."

A. Okay.

MR. OVERSTREET:

Your Honor, since we've . . .

A. I'm sorry.

MR. OVERSTREET:

Excuse me. Since we've broken the chain of questioning, maybe Mr. Raff could point us to what EWG he's suggesting is owned by AEP in the East, because we're not aware of any.

MR. RAFF:

If I can have a minute. Kentucky Power's Response to the Commission's 2nd Data Request, Item No. 12, Page 1 of 1, which I think there indicates 4,133 megawatts of unregulated generation.

MR. LITTLE:

Your Honor, we were not served with a copy of the 2nd Data Requests, answers to the 2nd Data Requests, so Mr. Ott does not have a copy.

CHAIRMAN HUELSMANN:

Why don't you make sure that you serve them with everything that you have? Are you aware of anything else you don't have?

MR. LITTLE:

That's it, Your Honor.

CHAIRMAN HUELSMANN:

That's it. As soon as you can, Mr. Overstreet.

MR. OVERSTREET:

I apologize, Your Honor.

CHAIRMAN HUELSMANN:

Those things happen.

MR. LITTLE:

Well, if we could have a copy provided to Mr. Ott.

MR. RAFF:

Sure.

CHAIRMAN HUELSMANN:

Could he take a look at Mr. Wagner's copy?

MR. RAFF:

I don't intend to go in any greater detail on this subject.

CHAIRMAN HUELSMANN:

Have you had enough time to review that?

A. I think I see these - if I can clarify, these generators in this analysis would not have been considered as part of AEP generation. These are owned by other companies.

Q. Okay. All right. Thank you.

CHAIRMAN HUELSMANN:

Okay.

Q. I believe you said your analysis had originally been done in response to a request from the Virginia Commission.

A. Yes. I don't know if I said that in here, but that's true.

Q. When did you actually do your analysis? There's a date on the bottom of this of 3-14-2003.

A. Right.

Q. Was that when it was printed?

A. Yeah, that's essentially when the report was finalized. The actual analysis itself was done between the period of December 2002 through probably mid February of '03.

Q. Okay, and there was some references in here about this being preliminary. Is that still . . .

A. I'm sorry. I didn't . . .

Q. Is it still preliminary?

A. Preliminary? Oh, I think the preliminary nature of it was really towards - this is sort of the base case analysis, if you will, in the sense of this sets a baseline. As we were talking through the process in Virginia, there was the indication that they would want to have a stakeholder process to request sensitivities to this analysis, meaning, for instance, what would happen if you assumed, you know, extremely hot weather. There's other things like that.

Q. All right. So this base case, then, is not subject to further revision?

A. No. The base case is final as it sits. I think there will be additional sensitivities performed, you know, in the future at some point, generally speaking, through a stakeholder process. In other words, we would have a fairly wide group of people ask for different types of analyses, so we could make sure and capture everyone's issue.

Q. Okay, and the request, - I guess it was a request by the Virginia Commission - was that for an analysis of the impact of AEP's membership in PJM rather than an analysis of the impact of the AEP utility that they operate in Virginia or that operates in Virginia, the impact on that particular utility?

A. The analysis, as I recall, was to look at the impact on Virginia utilities, if you will, or Virginia load of the formation of an RTO or the PJM expansion, I should say. So it really wasn't targeted towards a specific utility as much as what would the spot market prices and, you know, the related information be for the state of Virginia. That was really, I think, more the issue.

Q. Well, does Dominion operate essentially just in the state of Virginia?

A. Well, essentially, yes, but, to be perfectly clear, Dominion does have some load in North Carolina. I'm

not exactly sure what percentage. I understand it's small.
Q. But you didn't make an effort to separate out the Appalachian Power operations in Virginia; did you? I mean, this is . . .
A. No, I did not.
Q. Did you have the ability to do that?
A. It's very difficult to do, because today it's an integrated system, meaning it's served through a pooling or, from my perspective, it's served through, you know, a single security constrained economic dispatch, and, under a larger market, it would be, you know, served from, you know, another larger security constrained economic dispatch. To try to quantify it down to that level, which is really beneath the control area level, you would have to make a lot of assumptions about, you know, what I would call painting megawatts to try to assign megawatts directly and that would be difficult. It would be driven by assumptions. So generally we try to stay on the control area level. For instance, with Dominion, we reported Dominion as Dominion. We didn't try to separate the part of Dominion that was in Virginia. We just reported it as the whole control area.
Q. But you realize what you're showing here for AEP

represents the operations in seven states?
A. Yes.
Q. And I assume you realize that the statute upon which the Commission must judge this requested asset transfer, you know, requires a finding that transfer is in the public interest, and is it not possible that there could, in fact, be lower cost or savings to some of the members of the AEP System but then higher cost for other members?
A. I don't know how it - I guess it would depend on how you would construct it, but, if your hypothetical is you have a set of low-cost generators serving load today, those same low-cost generators would serve load tomorrow. The only way cost could increase for that load is if you somehow said, well, those low-cost generators no longer can serve that load. It has to be replaced by higher cost power, like, if we go back to our hypothetical where the $12 units were running in both cases. If those are directly assigned contractually or bilaterally or whatever to a certain load, then the worst that could happen is, you know, it would be a break even. The best that could happen is, during the times when those generators are off, the spot market could provide cheaper alternative power, but I don't see how, unless you change the basic

construct of how those generators were assigned, that you could see a cost increase.
Q. What about a drop in revenue?
A. A drop in revenue? For sales, you mean?
Q. Yes.
A. Well, since the spot market is voluntary, you know, if you have bilateral contracts in place to sell it today and the spot price were lower than those bilateral contracts, I mean, if you continued those, . . .
Q. No. I mean, to the . . .
A. . . . you may have more competition from a larger marketplace, but, I guess, if - because if the marketplace expanded, but I still don't see $12 generation being displaced because it's . . .
Q. No, I don't mean generation being displaced, but, to the extent that a utility has low-cost generation and it is a net exporter . . .
A. Right.
Q. . . . of energy, if the market price for that power, because of the larger size of the market, is lower, that it would then receive less revenue from off-system sales.
A. You mean lower than the current contract price?
Q. No. Lower than what it currently receives from its off-system sales . . .

A. Sure. Yeah. I mean, obviously it . . .
Q. . . . whether they're contract or not.
A. Sure, I mean, if the price would drop, if the locational price were lower. Remember, locational prices are based on margin. Most bilateral contracts are based on some sort of, you know, again - yes, it could. If the spot price were actually lower than the bilateral contract price, it could happen.
Q. Or if the spot price is lower than the spot market in which AEP now participates without being a member of PJM?
A. Yes, again, if that would happen, but I think, if you actually looked at the numbers, you're saying that the price of the energy would have to drop, you know, across the whole area, I think is what you're speculating.
Q. Well, back on this schedule, what you show the combined RTO change for load payments, the negative $932, does that not indicate that there is a total decrease in the spot market for energy assuming all energy is sold in the spot market?
A. Sure. Yes, it does. In this case, it shows a total reduction, but, again, you're assuming a marginal price in the individual runs that really doesn't exist today. Again, that's why we compare it with, you know,

multiple numbers to get an indication, but, if you looked at the marginal price on an individual scenario versus the marginal price in aggregate in the combined scenario, you will see a reduction in the overall marginal price; yes.

Q. Is there a spot market price that's created by the Cinergy trading hub?

A. I don't know if I would term it as spot price. I think it's more of a forward contract price.

Q. Do you know what impact there would be on those prices if Kentucky Power joins PJM?

A. No.

Q. On Page 8, Lines 10 and 11, of your testimony, . . .

A. Yes.

Q. . . . you say, "For the potential annual savings to wholesale load serving entities, . . ." Who are wholesale load serving entities?

A. AEP is a wholesale load serving entity.

Q. The five utilities that are part of the AEP Pool?

A. Yeah.

Q. Is it limited to those five, or does it include any other utility that is within the AEP footprint?

A. Well, these specific numbers are limited to those five, but obviously the potential for savings would extend to anyone in the marketplace, you know, because of the efficiencies, but, if you're asking for the specific numbers, they're limited to only the AEP load, if you will.

Q. All right.

A. For instance, it would not include AMP-Ohio, whose load is within the control area.

Q. Okay.

CHAIRMAN HUELSMANN:

Mr. Raff, do you think it's in order to maybe take a little break, . . .

MR. RAFF:

That will be fine.

CHAIRMAN HUELSMANN:

. . . or do you want to finish?

MR. RAFF:

We have a few more questions, but that's fine.

CHAIRMAN HUELSMANN:

It's up to you, if you want to finish out or you want to take a break.

MR. RAFF:

We can take a break; yes.

CHAIRMAN HUELSMANN:

Let's take a break to three-thirty. We'll stand in recess, then.

OFF THE RECORD

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CHAIRMAN HUELSMANN:

Okay. The record should reflect we're back in session. It's about three thirty-seven. Mr. Raff, I think you were asking questions.

MR. RAFF:

Yes. Thank you, Your Honor.

Q. On Page 8 of your testimony, Mr. Ott, Lines 16 through 18, it says, "The LSE operating within an RTO should see decreased generation production costs due to the increased efficiency in the market."

A. Right.

Q. Have we now established that that probably is not true for Kentucky Power?

A. Yeah. I mean, as we were on break, I was thinking about there are some times when the price, for instances, goes to zero in PJM's current market today. So there are some times and, again, small amounts where the price would actually fall down below what, you know, the mine mouth that we have today in PJM which is on the order of the $11-$12 range. I think the other issue is the cost of production during times when the cheap generation is out of service to supply the alternative generation, I think is also a time when you'll see a decreased cost. So I really didn't think of the zero prices when I was talking to you before, but I think that has existed or does happen.

Q. Well, what does Kentucky Power do then during those times? Does it shut down its baseload coal-fired generation for five to six hours during the late evening because it can buy it cheaper?

A. No. Generally what happens with those types of plant is they have an economic minimum amount that they can generate and an economic maximum. They just ramp down to minimum. For instance, when PJM West was formed, the traditional thinking was PJM West was - you know, you had about 8,000 megawatts of, you know, coal plant come in, and essentially, at midnight when it switched over, they were added into the market. They were over-generating by about 2,000 megawatts. So what we found was that, over the midnight periods, traditionally, in operations, they would just run flat out over the evenings or I shouldn't say "evenings." It's the early morning hours, and, again, it would really depend on the actual generation mix and other factors. Obviously, during the summer, you're not going to ramp down even over the evening hours, but, during the spring and fall, you will see that happening. What we saw with PJM West was, again, the kind of savings they saw in about an eighth month period with that kind of phenomena, even though they had coal plant predominant

was about - I think that we had done some analysis - something around $44 million. So essentially they still realized a savings even though, you know, their generation mix tended to be the cheaper coal.
Q. Well, would it be fair to assume that, if Kentucky Power experiences a very minimal decrease, if any, in its production cost, that the savings that you have projected would only minimally flow to Kentucky Power?
A. It would be safe to assume that, if you have a generator that is, you know, a $12 plant, and these periods where the price is zero are relatively limited. Now, I think that the only other issue you would raise is one of the times when those plants are not available, how do you get the replacement power. You may see some benefits in that area, too.
Q. On Page 12 of your testimony, Lines 4 and 5, you talk about the savings for the entire AEP System, and then you say, on Line 4, "The portion of those total savings will be allocated to Kentucky customers pursuant to the AEP Operating Agreement and its cost allocation processes."
A. Right.
Q. I mean, are you intimately familiar with the AEP Operating Agreement?
A. No.

Q. So you don't know, then, whether these costs will, in fact, be allocated to Kentucky Power or not; do you?
A. No, I don't know. This was based on a discussion I had had during this process with some AEP staff, but I don't specifically know exactly how the allocation works; no.
Q. Okay. So it's possible that all the savings could be allocated to the AEP members who have higher production costs than Kentucky Power?
A. Yeah, it could be that. I don't know the allocation procedures.

MR. RAFF:

Okay. Thank you, Mr. Ott. I think that's all my questions.

CHAIRMAN HUELSMANN:

Ms. Blackford?

CROSS EXAMINATION

BY MS. BLACKFORD:

Q. Good afternoon, Mr. Ott.
A. Good afternoon.
Q. You looked at Page 8 of your testimony, Lines 16 through 17, . . .
A. Right.
Q. . . . with Staff counsel. I wanted to ask you one other question about that.

A. All right.
Q. Your chart that you put in later that has been enlarged as Staff Hearing Exhibit 4 actually indicates that that general statement does not apply to AEP since it's going to see an increased generation production cost of $340 million; right?
A. Well, really, that's not true because they see an increased sale of $420 million. So, if you take the difference, it actually is a net efficiency gain. In other words, the reason their production cost is going up is not because they are seeing more expense to serve the load. It's because they're selling more. They're selling more, you know, at - if you look at the net purchased power - do you see what I mean?
Q. Uh-huh.
A. Okay.
Q. Uh-huh. So they will have basically a converse. They're going to increase their generation . . .
A. Right.
Q. . . . production but decrease their purchases or increased sales conversely?
A. Yeah, increase sales so that they're actually making a net profit, if you will. Essentially, when you have increased sales at, obviously, prices higher than the cost of production, you would see a profit and that is

a form of, you know, global savings, if you will.
Q. Turn, if you will, please, to Page 11 of your testimony.
A. Yes.
Q. There, on Line 11, you say, "Congestion costs exist in the market today and they are borne disproportionately by retail customers through the retail fuel adjustment clause or in base rates."
A. Right.
Q. Would you elaborate on that statement for me, please?
A. Right, and, again, when I used the word "market" there, it may be a bad use of terminology that exists really in the areas today that are Dominion, AEP, and the areas outside of the current PJM marketplace where, for instance, today, if you have transmission congestion exist on a system, potentially, generation has to be moved in order to control that out of economic merit order. So you may not be able to use the next cheapest generation because of what we call transmission security constraint.
Q. Uh-huh.
A. Under today's world, in the areas where markets do not exist, that cost would be borne by - you know, as increased production cost, so it would be borne by whoever gets assigned that production cost under

today's world. The alternative, of course, would be to do something called a TLR, transmission loading relief procedure, which would be to curtail those transactions that are causing the increased flow, but, again, in those cases, there has to be an actual power flow existing. So that's what I meant by that.

MS. BLACKFORD:

All right. Thank you. That's all of my questions.

CHAIRMAN HUELSMANN:

Mr. Kurtz?

MR. KURTZ:

Just very briefly, Your Honor.

CROSS EXAMINATION

BY MR. KURTZ:

Q. This sheet that Mr. Raff was asking so many questions about, . . .

A. Yes.

Q. . . . the blowup from your testimony, did you study the AEP system as a five-member Pool or as a three-member Pool?

A. I didn't study it as a - I studied it as, you know, a single security constrained economic dispatch. I didn't actually do, you know, a pooling type cost allocation, if you will. I just took all of the generation in that area to serve all of the load within the transmission security constraints.

Q. So you included all the Ohio generation in your analysis?

A. All generation that was in Dayton Power & Light, AEP control areas, and, of course, the Dominion, and PJM.

Q. Okay. Does PJM have a prohibition on a utility or, I guess, what you would call a load-serving entity selling all of its generation into the PJM day-ahead or spot markets?

A. A prohibition against it?

Q. Yes.

A. No.

Q. So a utility could sell all of its generation into those markets if it wanted to?

A. Yes, it could sell it in two different ways. It could offer it in, you know, at some price, and PJM could dispatch it based on those, or it could self schedule it in and become what we would term as a price taker, meaning it would just take whatever the clearing price turned out to be.

Q. And then, conversely, there's no prohibition against a utility or a load-serving entity buying all of its requirements from the PJM day-ahead or spot markets?

A. Correct.

Q. Okay. Do you have a general idea of how much Kentucky Power receives for its generation resources based upon the cost-based rates it receives in Kentucky?
A. Not directly, no.
Q. Do you know whether, as a general matter, just theoretically, Kentucky Power could receive more money for its generation by selling it into the PJM market versus selling it at cost-based rates in Kentucky?
A. I don't know whether they could or not. I mean, it would depend on, you know, their current, you know, contractual obligations, etc. If you're saying would the spot price generally be attractive for a generator that's, you know, a $12 generator, the answer is yes, if that's your question.
Q. Yeah. So you don't know whether or not Kentucky Power, theoretically, could earn more revenue by selling all of its power into PJM at those market-based rates rather than selling it in Kentucky at cost-based rates?
A. No, I . . .
Q. You don't know?
A. No.

MR. KURTZ:

Okay. Thank you, Your Honor.

CHAIRMAN HUELSMANN:

Mr. Overstreet?

MR. OVERSTREET:

Nothing, Your Honor.

CHAIRMAN HUELSMANN:

Redirect?

MR. LITTLE:

No redirect, Your Honor.

CHAIRMAN HUELSMANN:

Okay. Does anyone have any - well, if there's no redirect, there's no recross. Okay. May this witness be excused? Thank you, sir. I believe that concludes your case.

MR. LITTLE:

Yes, it does, Your Honor.

CHAIRMAN HUELSMANN:

I guess . . .

MR. RAFF:

If we could have introduced the Staff Cross Exhibit No. 4, please.

CHAIRMAN HUELSMANN:

Staff No. 4? Does anybody object to Staff No. 4? It's previously in there.

MR. LITTLE:

As modified by Mr. Ott's correction.

CHAIRMAN HUELSMANN:

Right, the "4" is taken off?

MR. LITTLE:

Yes.

PSC EXHIBIT 4

CHAIRMAN HUELSMANN:

Okay. That concludes the hearing. Do we have a procedural schedule for briefs? Do we want to have a procedural schedule for briefs?

MR. LITTLE:

Yes, Your Honor. Do parties . . .

CHAIRMAN HUELSMANN:

We would like to have that? I assume AEP would like this Order out yesterday.

VICE CHAIRMAN GILLIS:

At least by July 1, '04.

CHAIRMAN HUELSMANN:

At least by July 1, '04. So . . .

MR. OVERSTREET:

Or when the FERC orders us to do it.

CHAIRMAN HUELSMANN:

Anybody have any suggestions? How long is the transcript going to be?

REPORTER:

The 9th.

CHAIRMAN HUELSMANN:

April 9?

REPORTER:

Yes. It will probably be the 4th really, but the 9th is when it's due.

CHAIRMAN HUELSMANN:

Thirty days?

MR. OVERSTREET:

That will be fine.

CHAIRMAN HUELSMANN:

May 9 for the applicant. Do you need 30 days from their brief?

MR. RAFF:

I think simultaneous briefs . . .

CHAIRMAN HUELSMANN:

Okay, 6-9 for the intervenors and 15 days for reply, or do you need a reply, or do we do replies?

MR. OVERSTREET:

We could either do that, Your Honor, or we could do simultaneous briefs, but it's whatever the Commission's . . .

CHAIRMAN HUELSMANN:

Give them 15 days? That will be the 24th.

MR. RAFF:

Usually we just have simultaneous briefs, Your

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Honor.

CHAIRMAN HUELSMANN:

Oh, do we normally have simultaneous briefs?

MR. RAFF:

Yeah.

CHAIRMAN HUELSMANN:

Due May 9 everybody? Okay. Anybody object to that? It'll be simultaneous briefs due on May 9 or whatever - if that's a Saturday or Sunday, the next Monday. How's that? It's close to Derby. So okay. Is there anything else that we need to take up?

MR. LITTLE:

May I ask a clarifying question?

CHAIRMAN HUELSMANN:

Sure.

MR. LITTLE:

Are we just doing an initial brief and no reply briefs now?

CHAIRMAN HUELSMANN:

That's my understanding.

MR. LITTLE:

Okay. Okay. Thank you.

CHAIRMAN HUELSMANN:

And that's pretty much consistent, Mr. Little, but this was a little different.

MR. LITTLE:

Okay.

CHAIRMAN HUELSMANN:

I thought maybe - I reverted to my lawyer days. Okay. Anything else? Okay.

MR. RAFF:

There have been a couple of requests for information. I assume that's 14 days from today?

CHAIRMAN HUELSMANN:

Yeah, that's the normal thing, and, if there's any problem with that, I'm sure we can work out a change, and, if we need to change this May 9 date for any reason, like going to the Kentucky Derby, then I think we can all work that out. Mr. Little, thank you for coming. Nice to have you here, and, Mr. Caldwell, I think that this is your first time here, and you've been doing this how long, involved in energy matters? A month?

MR. CALDWELL:

On this . . .

CHAIRMAN HUELSMANN:

I think we're going to give you a test about this. It's tough stuff; isn't it? Tough stuff. Thank you all for coming. That will conclude the hearing.

FURTHER THE WITNESSES SAITH NOT

HEARING ADJOURNED

OFF THE RECORD

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STATE OF KENTUCKY

COUNTY OF FRANKLIN

I, Connie Sewell, the undersigned Notary Public, in and for the State of Kentucky at Large, do hereby certify the foregoing transcript is a complete and accurate transcript, to the best of my ability, of the hearing taken down by me in this matter, as styled on the first page of this transcript; that said hearing was first taken down by me in shorthand and mechanically recorded and later transcribed by me; that the witnesses were first duly sworn before testifying.

My commission will expire November 19, 2005.

Given under my hand at Frankfort, Kentucky, this the 4th day of April, 2003.

Connie Sewell

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